federal register

Friday
February 27, 1981

Part V

Department of the Interior

Geological Survey

Final Outer Continental Shelf Orders Governing Oil and Gas Lease Operations in the Arctic

DEPARTMENT OF THE INTERIOR

Geological Survey

Final Outer Continental Shelf Orders Governing Oil and Gas Lease Operations in the Arctic

Notice is hereby given that under Title 30 of the Code of Federal Regulations, § 250.11, the Deputy Chief, Conservation Division—Offshore Minerals Regulation, U.S. Geological Survey (USGS), has approved the issuance of final Outer Continental Shelf (OCS) Orders Nos. 1, 2, 3, 4, 5, 7, 8, and 12 for the Arctic Area of the Gulf of Alaska Region. These Orders will be effective February 27, 1981.

The analysis contained in the Environmental Assessment (EA) of the proposed Arctic OCS Orders and the comments received regarding that analysis were considered prior to making a decision to issue these final Arctic OCS Orders. In accordance with the Council on Environmental Quality regulation (45 CFR 1508.13), a document entitled "A Finding of No Significant Impact" has been prepared for the issuance of these Orders. This document is available, upon request, from the Deputy Conservation Manager and the Deputy Chief, Conservation Division—Offshore Minerals Regulation, at the addresses listed below.

Lessees cannot explore for oil and gas in the Arctic OCS Area until they have an exploration plan approved by the USGS. Many of the standards for approving these plans are set by the Arctic OCS Orders. A lessee already has filed an exploration plan with the Deputy Conservation Manager, Offshore Field Operations, Alaska OCS Region. Under this plan, the lessee proposes to build gravel islands in the Beaufort Sea lease sale area. Due to the loss of favorable ice conditions in the Arctic, these islands cannot be built this year unless construction begins by March 1, 1981. A need exists to have the Orders take effect by this date, so that the USGS may approve or disapprove the exploration plan.

Industry will not need the additional time to comply with these Orders before the effective date. These Orders have been available to industry in virtually the current form since June 13, 1979 (44 FR 34060), and are similar to existing Orders in other OCS regions. Lessees have had an adequate opportunity to adjust their plans to these requirements. We, therefore, find good cause not to wait 30 days before having these Orders take effect. See 5 U.S.C. § 553(d)(3).

These Orders incorporate appropriate suggestions received in response to the following Federal Register Notices published on:

1. June 13, 1979 (44 FR 34060), requesting comments on the proposed version of Arctic OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12.

2. June 29, 1979 (44 FR 38004), June 29, 1979, requesting comments on the final versions of OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12 for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Regions, and referred to the Arctic OCS Orders, as published on May 18, 1979 (44 FR 29258).

3. July 2, 1979 (44 FR 38676), requesting comments on proposed OCS Order No. 8 and proposed "Operating Procedures for the OCS Platform Verification Program" for the Gulf of Mexico, Pacific, Gulf of Alaska, Atlantic, and Arctic OCS.

4. September 27, 1979 (44 FR 55670), postponing the effective date of the Orders to December 1, 1979, and announced that the final Orders would include the final versions of Arctic OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12. The December 1, 1979, effective date was subsequently extended to January 1, 1980, by Notice on November 30, 1979 (44 FR 69040).

5. December 21, 1979 (44 FR 76212), promulgating OCS Orders Nos. 1, 2, 3, 4, 5, 7, 8, and 12, effective January 1, 1980, for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Regions. This Notice generated unsolicited comments applicable to the Arctic OCS Orders.

6. April 10, 1980 (45 FR 24713), requesting comments on proposed revisions of portions of final OCS Orders Nos. 1, 2, 5, and 7 for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Regions. Comments relative to the Arctic Area were also invited, since these proposed revisions are also applicable to the Arctic OCS Orders.

7. August 18, 1980 (45 FR 55126), publishing final revisions of certain requirements of OCS Orders Nos. 1, 2, 5, and 7, effective September 15, 1980, for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Regions. This Notice and the final Orders also include responses to appropriate suggestions received at a public meeting held at the USGS National Center in Reston, Virginia on May 20, 1980. These responses and suggestions are applicable to the Arctic OCS Orders.

8. December 19, 1980 (45 FR 83868), requesting comments on an EA of the potential environmental effects of issuing the proposed Arctic OCS Orders.

These Orders have also been revised to reflect the revision of the operating regulations contained in 30 CFR 250, which implements the Outer Continental Shelf Lands Act (OCSLA) Amendments of 1978. These regulation revisions were published on October 26, 1979 (44 FR 61886), with an effective date of December 13, 1979. Accordingly, it should be noted that the preamble and the text of each Order cite the regulations as revised.

Arctic OCS Order No. 8 incorporates, by reference, the document entitled "Operating Procedures for the OCS Platform Verification Program," October 1979. The original proposed version of this document was published with a proposed OCS Order No. 8 for the Gulf of Mexico, Pacific, Gulf of Alaska, Atlantic and Arctic OCS on July 2, 1979 (45 FR 38676). A summary of comments, discussions, and the final version of the document were published for the Gulf of Mexico, Pacific, Gulf of Alaska and Atlantic OCS Regions on December 21, 1979 (44 FR 75254). This version of the document is hereby adopted by reference into the Arctic OCS Order No. 8. The USGS is currently revising this document and will publish a revised version in the future.

In accordance with the USGS Director's Delegation of Authority, published on March 14, 1980 (45 FR 16570), the title, "Oil and gas Supervisor," has been changed to "Deputy Conservation Manager." Authority of the Chief, Conservation Division, to approve Orders has been delegated to the Deputy Chief, Conservation Division—Offshore Minerals Regulation.

It should be noted that some of the requirements of these Orders will be revised in the near future to reflect the implementation of the "Memorandum of Understanding Between the United States Geological Survey of the Department of the Interior and the United States Coast Guard of the Department of Transportation concerning Regulation of Activities and Facilities on the Outer Continental Shelf of the United States," which was signed on December 18, 1980 and published on January 8, 1981 (45 FR 2199).

Comments were received from the following organizations:

Alaska Legal Services Corporation.
Alaska Oil and gas Association.
American Bureau of Shipping.
AMOCO Production Co.
ARCO Alaska, Inc.
Atlantic Richfield Co.
Axelson, Inc.
Brown & Root, Inc.
Chevron USA, Inc.
Chicago Bridge and Iron Co.
Continental Oil Co.
Det Norske Veritas.
Engineering Specialties, Inc.
Exxon Company, USA.
Friends of the Earth, Alaska Office.

Getty Oil Co.
Gulf Oil Exploration and Production Co.
Hunt Oil Co.
J. Ray McDermott & Co.
Lone Star Steel Co.
Marathon Oil Co.
Massachusetts Executive Office of Environmental Affairs.
National Ocean Industries Association.
National Wildlife Federation. Natural Resources Defense Council, Inc.
Offshore Operators Committee.
Otis Engineering Corporation.
Pace Marine Engineering Systems, Inc.
Pennzoil Co.
Phillips Petroleum Co.
Shell Oil Co.
Sohio Alaska Petroleum Co.
State of Alaska, Office of the Governor.
Sun Production Co.
Tennessee Gas Pipeline.
Terris and Sunderland, Counsel for the North Slope Borough of Alaska.
Texaco, Inc.
Tiedemann, H. M., and Co., Inc.
Trans-Continental Gas Pipeline Corporation.
Trustees for Alaska.
Union Oil Company of California, Gulf and Western Regions.
U.S. Department of Commerce, National Oceanic and Atomospheric Administration.
U.S. Department of the Interior, Fish and Wildlife Service.
U.S. Environmental Protection Agency.
U.S. Navy, Naval Facilities Engineering Command.
Ziontz, Pirtle, Morisset, Ernstoff and Chestnut, on behalf of the Inupiat Community of the Arctic slope.

In order to facilitate our discussions of the comments received and the presentation of the final version of the Orders, this Notice is organized under the following general headings:

I. Summaries and Discussions of Comments Received in Response to Federal Register Notices Published Through August 18, 1980

This section discusses the comments received on the **Federal Register** Notices listed above in items 1 through 7 and explains the revisions to the June 13, 1979, proposed Arctic Orders as presented in the Appendix of the EA which was published on December 19, 1980 (45 FR 83888). Refer to item 8 above.

Some of the comments and discussions published on December 21, 1979 (44 FR 76212), are repeated in this publication for the convenience of the readers. In certain instances, the revised portions of paragraphs and subparagraphs are indicated in italics.

II. Summaries and Discussions of Comments Received in Response to Federal Register Notice (45 FR 83868) on the Environmental Assessment

This section discusses the comments pertaining to the analysis of the environmental effects of the proposed Arctic Orders and alternatives.

III. Final Arctic OCS Orders

This section contains the final Arctic OCS Orders Nos. 1, 2, 3, 4, 5, 7, 8, and 12.

The term "OCS area," as used herein, is defined as an established organizational unit of a USGS region under the jurisdiction of a deputy Conservation Manager. An area is comprised of one or more districts, each of which is under the administration of a District Supervisor.

Arctric OCS Orders are applicable to leases on the OCS of the Beaufort Sea, Chukchi Sea, and the Hope Basin. The term "Outer Continental Shelf" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (Public Law 31, 83rd Congress, 1st Session), and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

For further information, contact Mr. David Schuenke Chief, Branch of Rules and Procedures, Conservation Division, USGS, Mail Stop 640, 12201 Sunrise Valley Drive, Reston, Virginia 22092 (703–860–7395). The primary authors of this document are Mr. Rodney A. Smith, Deputy Conservation Manager, Mr. Rishi Tyagi, Chief, regulations and Orders Section, and Mr. stan Radack, Chief, engineering and Operations Section, Offshore Field Operations, USGS, Alaska OCS Region, P.O. Box 259, Anchorage, Alaska 99510 (907–271–4303); Mr. Lloyd M. Tracey, chief, OCS Orders and Standards Section, and Mr. Ray Beittel, Office of the Deputy Chief, Conservation Division—Offshore Minerals Regulation, USGS, Mail Stop 640, National Center, 12201 Sunrise Valley Drive, Reston, Virginia 22092 (703–860–7395); and Mr. Poe Leggette, Office of the Solicitor, Department of the Interior, Mail Stop 600, National Center, 12201 Sunrise Valley drive, Reston, Virginia 22092 (703–860–6736).

Copies of this Notice are available from the following:

Deputy Conservation Manager, Offshore Field Operations, U.S. Geological Survey, Alaska OCS Region, P.O. Box 259, Anchorage, Alaska 99510.
Deputy Chief, Conservation Division—Offsore Minerals Regulation, U.S. Geological Survey, Mail Stop 640, National Center, 12201 Sunrise Valley Drive, Reston, Virginia 22092.

Booklet copies of the final Arctic OCS Orders will be availalbe from the Deputy Conservation Manager and the Deputy Chief, Conservation Division—Offshore Minerals Regulation, at the addresses listed above in approximately 60 days after the effective date of these Orders.

Copies of the USGS Standards referenced in Arctic OCS Order No. 2 are available from the Deputy Chief, Conservation Division—Offshore Minerals Regulation, at the address above.

Dated: February 17, 1981.

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

I. Summaries and Discussions of Comments Received in Response to Federal Register Notices Published Through August 18, 1980

General Comments

Comments. One commenter noted that the term "operator" had been replaced with the term "lessee" throughout the revised OCS Orders. The commenter also contended that "There appears to be some confusion between drilling 'contractor' and 'operator.' We agree that the drilling 'contractor' is the lessee's agent and that the 'lessees' are generaly responsible for drilling and development of the lease. Therefore, with regard to provisions addressing legal liabilities, 'lessee' would be correct. However, many of the provisions apply to operational questions, such as submission of forms, reporting, etc. We suggest that the 'operator' is the proper party in those instances, not the lessee (non-operator). In those instances, the lessee (non-operator) would have to first obtain the information from the operator before it could respond. This requirement would be unnecessary, burdensome, and inefficient. We urge you to direct such requirements to the 'operator' not 'lessee' (non-operator) with regard to operational activity."

Discussion. As indicated on May 18, 1979 (44 FR 29261), under the discussion for the revisions of subparagraph 2.1.1 of OCS Order No. 2, the USGS maintains that the lessee is legally responsible for all requirements for compliance, including drilling and developing the lease. The USGS recognizes that much of the information which is required must be submitted in behalf of the lessee(s) by the operator.

The Preambles of OCS Orders Nos. 2 and 5 were revised to clarify that certain required information may be submitted by the "designated lease operator."

OCS Order No. 1

Paragraph 1

Comments. One commenter suggested that the Order should provide different requirements for large and small

structures. Another commenter suggested that the Arctic Order should provide requirements for artificial islands.

Discussion. These suggestions were adopted.

Paragraph 1 was reorganized into three subparagraphs: 1.1, *Large Platforms and Structures;* 1.2, *Small Structures;* and 1.3, *Artificial Islands.*

The requirements for large platforms are the same as the original Order. The requirements for small structures are the same as the existing OCS Order for the Gulf of Mexico Region and are consistent with the U.S. Coast Guard requirements. The requirements for artificial islands are applicable only to the Artic Areas.

Paragraph 2

Comments. One commenter suggested that the entire paragraph be deleted, since the sign required by the Order would create an unnecessary hazard during its installation and during subsequent drilling operations.

Discussion. The USGS disagrees. This requirement is in accordance with 30 CFR 250.37, which requires each drilling structure to be clearly identified. The sign need not create a hazard, since it may be affixed outside the derrick and need not interfere with the drilling operations. The Order was revised to allow the option of installing the sign on the heliport. We consider these signs necessary to facilitate the identification of particular floating drilling vessels from the air, especially during emergency conditions.

Comments. One commenter suggested that the words "floating platforms" should be added to the first sentence.

Discussion. The USGS agrees with the intent of this suggestion; therefore, the Order was revised by deleting the word "semisubmersible." The words "floating platforms" are considered to be all inclusive.

Paragraph 4

Comments. One commenter believes only potentially hazardous or sizable submerged objects should be reported to the U.S. Coast Guard. The U.S. Coast Guard also expressed concern that excessive reports are being filed because the currently effective Orders for the active areas do not place any limitations on the reportable objects.

Discussion. The USGS has accepted this suggestion and revised paragraph 4 of OCS Order No. 1, as indicated in section III of this Notice. The U.S. Coast Guard will forward all reports disclosing potential obstructions to the National Marine Fisheries Service for appropriate inclusion on the list of obstructions to fishing devices. This list is published in the Weekly notice to Mariners by the Defense Mapping Agency Hydrographic/Topographic Center, and is distributed to all USGS District Supervisors. This publication is available from: DMAOOS, Code IMA, 650 Brookes Lane, Washington, DC 20315.

The U.S. Coast Guard also intends to publish a Notice outlining the method of position fixing.

Comments. It was suggested that the last sentence concerning permanent markers should be deleted from the Arctic Order because ice and ice flows would be hazardous to these devices.

Discussion. The U.S. Coast Guard District Commander will consider all environmental conditions in determining marking requirements. The District Commander has the prerogative of granting departures from this requirement where permanent markers are impractical.

Comments. There was a wide divergence of opinion on the proposed revision of this paragraph, as published on April 10, 1980 (45 FR 24713). One commenter agreed with the proposed revision; another contended that the 40-pound limitation on the reporting of objects was too low; and another contended that this limitation was too high. The first commenter stated, "* * * a 6" ANSI 600 series weld neck flange weights 73 lbs., and an 8" ANSI 600 series flange weighs 112 lbs., and these should not be considered an obstruction." This commenter suggested that the limitation should be 120 pounds or less; another suggested the limitation should be 150 pounds. The opposing view maintains that 55-gallon drums are a major cause of net damage. It was contended that "* * * platform workers knock holes in the drums and throw them into the Gulf rather than return them to the shore. The drums weigh less than 40 pounds empty, but on the sea floor filled with mud, they weigh half a ton or more. Often they rip through the net wings or through the bottom of the net causing the loss of a catch."

This commenter also contended that batteries and diesel fuel filters also weigh less than 40 pounds, and these items have caused damage to fishing nets.

Discussion. The 40-pound weight limitation was selected because the USGS determined that a 55-gallon steel drum without a top weighs approximately 42 pounds. Therefore, any 55-gallon steel drum lost, with or without a top, would be required to be reported. The disposal of material such as containers, batteries, and diesel fuel filters is prohibited by OCS Order No. 7, subparagraphs, 1.2, *Solid Material Disposal,* 1.2.2, *Containers,* and 1.2.3, *Equipment.* Engine starting batteries weigh 45 to 55 pounds and, therefore, would be reportable items. It appears that the 40 pound weight limitation is reasonable.

Comments. It was suggested that subparagraph 4b of the April 10, 1980 (45 FR 24713) version of the proposed revision of paragraph 4, should be revised to separate the weight limitation from the configuration limitation. It was contended that the configuration limitation should be treated alone, since it alone provides sufficient reason for exclusion

Discussion. The USGS disagrees with the contention. The intent was to require the reporting of light bulky items which would damage fishing nets, regardless of weight.

Comments. It was suggested that a new subparagraph should be added to the Order as follows: "Are located within 150 feet of fixed structures on which approved aids to navigation are maintained." It was contended that prudent fishermen would maintain this distance for safety.

Discussion. The USGS agrees with the intent of this suggestion and has revised the subparagraph to include a new subparagraph 4c, as follows: "c. Are *determined to be located on the sea floor* within 46 meters (150 feet) of fixed structures on which approved aids to navigation are maintained."

The phrase "determined to be located on the sea floor" was added because an accidentially dropped object may roll or be carried by currents more than 150 feet from the structure and, therefore, could present a hazard to fishing gear.

Paragraph 5. Marking of Equipment

Comments. Several commenters commented on the content of this paragraph, which was added to the final Orders for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic Regional Orders on December 21, 1979 (44 FR 76216). This paragraph was added in accordance with the new regulation, 30 CFR 250.54, which was published on October 26, 1979 (44 FR 61886). This new regulation implements section 403(b) of the OCSLA Amendments of 1978.

Discussion. As stated on April 10, 1980 (45 FR 24713), appropriate comments received in response to the solicitation for comments on 30 CFR 250.54 would be considered in the development of the final revision of paragraph 5 of OCS Order No. 1. These comments were incorporated into a proposed revision of paragraph 5 which was published on June 16, 1980 (45 FR 40669). Comments were requested to be submitted by August 15, 1980. These

comments are being analyzed and appropriate suggestions will be incorporated into a reproposal of paragraph 5 to be published in the **Federal Register** in the future. The subsequent paragraph, entitled "Departures," was renumbered.

OCS Order No. 2

Preamble

Comments. No comments received.

Discussion. A sentence was added referring to the requirements for "Electrical Equipment," "Welding Practices and Procedures," and "Employee Orientation and Motivation," specified in OCS Order No. 5 for production safety systems and applicable to drilling rigs.

Subparagraph 1.1a

Comments. It was proposed that the requirements of subparagraph 1.1a regarding drilling of a relief well, be elaborated and more specific relative to time within which the drilling of the relief well had to be commenced.

Discussion. Operators will be required to identify in their plan for exploration or plan of operation a means of drilling a relief well. The plan will be based on the season for which the operation is proposed, the distance from shore and the offshore islands, water depth, the depth of the proposed wells and prospective hydrocarbon zones, the type of operation and type of other drilling operations in the area such as gravel island, ice island, drillship, and barge, and the status of new technical developments.

Requirements specifying the type of drilling unit that must be used and the maximum permissible time for site preparation are intentionally omitted because of the large number of variables affecting relief well decisions. The relief well options proposed by the operator will have to be acceptable to the District Supervisor from a timing and a technical standpoint.

Paragraph 1.1

Comments. It was suggested that, in addition to subsections 1.1a, 1.1b, and 1.1c, a subsection be added requiring provisions for dealing with normal and emergency operations during three separate seasonal conditions and for dealing with possible fire involvement.

Discussion. The first suggestion was adopted and the following subsection 1.1d was added: "1.1d. Hazards unique to the site of the drilling operations, including conditions such as solid ice cover freezeup and breakup." Requirements for firefighting systems are covered under subparagraph 5.1.8 of OCS Order No. 5.

Subparagraph 1.2

Comments. Several commenters stated that the last sentence should be revised to require "if drilling activity does not commence within 6 months," be changed to "12 months." It was contended that the 6-months requirement will "create new problems as a result of rig scheduling, partnership agreements and availability of equipment."

Another commenter stated that the last sentence in this subparagraph should be changed to provide "if drilling activity does not commence within one year after approval date, the permit will expire unless an application for extension due to unusual circumstances is made to the District Supervisor."

Discussion. The USGS considered the reasons submitted for the proposed change. The last sentence of subparagraph 1.2 was deleted, because diligence requires that drilling should proceed as soon as possible after an Application for Permit to Drill has been approved. If drilling is delayed for valid reasons the District Supervisor may reevaluate his approval at the time drilling is to commence.

Subparagraph 2.1.1.

Discussion. The following editorial revisions were made to improve the organization of the requirements. A sentence was added to make it clear that the information need not be resubmitted when a unit moves about in a given area or returns to an area where the drilling unit had been previously approved, unless there were changes in equipment which affect the rated capacity of the unit. This sentence was formerly contained in subparagraph 2.2c, *Mobile Drilling Units,* and was moved to subparagraph 2.1.1, because the requirement is applicable to drilling rigs on mobile drilling units and fixed structures. The requirements of subparagraph 2.1.1f were formerly contained in subparagraph 2.2a. It is considered that this requirement should more appropriately be placed under "General Requirements," because it applies to fixed and mobile drilling units.

Comments. It was suggested that this Order should specify the extreme oceanographic and meteorological conditions "which must be withstood" by the drilling units.

Discussion. This suggestion was not adopted because the oceanographic and meteorological conditions vary from area to area, and from season to season; therefore, it is necessary to evaluate each drilling unit on a site-specific case-by-case basis. This subparagraph was revised by adding the phrase "and ice conditions" to the first sentence. It is considered necessary that this parameter be included, since ice conditions can affect the fitness of the drillng unit.

Comments. One commenter suggested that the drilling units be equipped with a mud circulation pump which can be used in case a generator blackout.

Discussion. We have determined that the addition of this requirement is unnecessary. Drilling units proposed for use by the lessees are routinely checked to ensure they incorporate redundancy in emergency backup equipment, consistent with the current state-of-the-art and also meeting the requirements of BAST. It is common practice to equip Arctic drilling rigs with multiple mud pumps with independent power sources.

Subparagraph 2.1.3

Discussion. This subparagraph was revised to provide for those areas where sufficient geophysical data has been collected to prepare a comprehensive report on the geological hazards which the District Supervisor will evaulate to determine if additional shallow geologic hazard surveys are required. The phrase, "* * * or other surveys required by the Deputy Conservation Manager (DCM, Offshore Field Operations)" was added because the DCM may require other surveys, such as archaeological surveys or biological surveys, to be conducted in certain areas, as stipulated by lease terms.

Comments. Several comments received in response to the final version of subparagraph 2.2, *Mobile Drilling Units,* item "c," for the Pacific, Alaska and Atlantic Regions published on December 21, 1979 (44 FR 76223), and a proposed revision published on April 10, 1980, (45 FR 24713), prompted the USGS to reevaluate the requirements for the submittal of seabed data for all regions of the OCS.

Discussion. The USGS has reviewed the criteria for requiring these data and has determined that seabed data is important not only for the determination of the stability of mooring points for mobile units, but also for fixed drilling platforms, and for the stability of the location for subsea blowout-preventer stacks. Therefore, the USGS revised the requirement to allow the District Supervisors to selectively require the submittal of the data as indicated below. It should be noted that since this requirement is applicable to mobile and fixed drilling units, it is appropriate to include this requirement under the heading of *General Requirements* and

the subheading of *Well-Site Surveys*, rather than under the heading 2.2, *Mobile Drilling Units*, item "c," as indicated in the December 21, 1979 (44 FR 76223) version of the subparagraph. Therefore, this requirement was deleted from subparagraph 2.2 and incorporated into subparagraph 2.1.3 *Well-Site Surveys*, by adding the following sentence:

When requested, this data shall include sediment and seabed data, e.g., seabed profiles, sediment consistency, allowable bearing and sliding loads, and nearby potential seabed hazards, i.e., sand waves, slumps, mud slides, permafrost, and deposits of frozen gas hydrates.

Subparagraph 2.1.4

Comments. It was suggested that this subparagraph should include a requirement to monitor and report ice conditions.

Discussion. The USGS agrees; the phrase "and monitor ice conditions" was added to the first sentence.

Comments. Several commenters suggested that the section be revised to require this data collection only as needed for early area planning and to provide for its possible discontinuation once sufficient data were available for a given area.

Discussion. The proposed suggestion has merit and the requirement was modified to read, "Where such information is not readily available, lessees shall collect and report oceanographic, meteorological and performance data, and monitor ice conditions during the period of operation. The type of information collected, method of collection, and report requirements will be as specified by the DCM, Offshore Field Operations."

Subparagraph 2.2a

Comments. No specific comments were received. This subparagraph was revised in response to general comments received on the Final Orders for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic Regions published on December 21, 1979 (44 FR 76223).

Discussion. This subparagraph was revised to require a listing of the maximum environmental and operational conditions used for the design. This revision is a clarification of the previous wording. The reference to the Critical Operations and Curtailment Plan was deleted from subparagraph 2.2a and was incorporated as item "f" of subparagraph 2.1.1. Refer to the discussion for the revision of subparagraph 2.1.1.

Subparagraph 2.2b

Comments. No comments received.

Discussion. The requirement was revised to include a listing of ice loading and unusual site-specific environmental conditions.

Subparagraph 2.3

Comments. No comments received.

Discussion. The following sentence was added to subparagraph 2.3, *Fixed Drilling Platforms: "Mobile drilling units which have their jacking equipment removed, or have been otherwise immobilized, will be considered fixed drilling platforms and applications shall also be submitted in accordance with OCS Order No. 8."* This sentence was added to clarify the requirement when a "mobile drilling unit" is converted to a "fixed drilling unit."

Subparagraph 3.1

Comment. One commenter questioned the usefulness of the requirement for the cements used to cement through permafrost zones to have low heat of hydration; another commenter questioned the use of the word "excessive" in the fourth sentence.

Discussion. The fourth sentence of this subparagraph was modified to read, "The cement used to cement through permafrost zones shall be designed to set before freezing and shall have a low heat of hydration so as not to thaw frozen formations." The USGS considers the use of gypsum based cements having a low heat of hydration is a proven successful method of cementing in permafrost zones.

Comment. One commenter recommended that cementing of casing shall always be checked by running a cement bond log.

Discussion. USGS reviewed this comment and believes the present requirements of subparagraphs 3.1 and 3.6 adequately address testing of cement jobs and remedial cement jobs.

Comments. It was suggested that the sixth sentence of subparagraph 3.1 should be revised as follows: (1) Delete the requirement "12 meters (39 feet) below the ocean floor" and (2) Insert "the depth of the structural casing shoe." It was contended that "placement of the mudline suspension starting ring should determine the depth at which cement should be removed below the mudline. Sufficient data is not always available to place the starting ring within 39 feet of the mudline."

Discussion. The USGS agrees with the commenter's reasons for the suggestion. This suggestion was adopted.

Comments. It was suggested that the penultimate sentence of the first paragraph be revised by inserting the phrase "after consulting with," in lieu of "in accordance with the instructions of."

Discussion. This suggestion was not adopted. The proposed phrase implies that anything the lessee proposes to do would be acceptable to the District Supervisor. The phrase, "* * * as approved by the District Supervisor" was adopted.

The first sentence of the second paragraph of 3.1 listing design criteria was reworded for editorial clarity.

Comments. One commenter objected to the December 21, 1979 (44 FR 76214) version of subparagraph 3.1c, which was changed from "maximum anticipated surface pressure" to "anticipated surface pressure." The commenter contended, "However, it now appears that some USGS [District] supervisors have interpreted 'anticipated surface pressure' to be determined considering only gas in the hole, which can result in certain wells not being drilled." This revision also impacts subparagraph 5.1.1, *Blowout Preventer (BOP) Equipment Requirements*, which requires that the working pressure of any BOP shall exceed the anticipated surface pressure to which it may be subjected.

Discussion. The USGS determined from comments received that industry uses a variety of methods to determine the design wellhead pressure for surface and production casing strings and in the selection of BOP stack and wellhead working pressure levels. For example, one company assumes the design pressure used in designing the casing string and selecting the wellhead BOP working pressures is equal to a column of dry gas times a factor equal to the square root of the ratio of 4,000 divided by the casing setting depth. Another company uses a factor of 62½ percent of the anticipated maximum bottom hole pressure. Another company sizes BOP equipment to withstand ⅓ of the estimated bottom hole pressure at the next casing depth. In recognition of the divergence of opinion on this subject, the USGS revised the second paragraph of subparagraph 3.1, as shown below. This revision will allow the USGS to identify any design wellhead pressures that appear inconsistent with normal industry practice. This procedure will also allow industry to evolve and apply new criteria as they are developed. The revisions of the subparagraph are indicated in italics. The italicized revision renders the first sentence of the second paragraph of subparagraph 5.1.1 redundant; therefore, this sentence was deleted. It should be noted that a proposed revision of this subparagraph was published on April 10, 1980, (45 FR

24714) and that the final version, as published below, is responsive to comments received on that version, and comments received at a public meeting at the USGS National Center in Reston, Virginia on May 20, 1980. Additional comments on the April 10, 1980 version are discussed below.

Comments. It was suggested that the last sentence of the April 10, 1980 (45 FR 24714) version of the footnote should be revised to state, "The lessee shall include as part of the statement of anticipated surface pressure a statement containing the calculations used to determine this pressure during the drilling phase, the completion phase, and the anticipated surface pressure used for production string design."

It was contended that "The anticipated surface pressure for production purposes through the production casing is usually based on the estimated bottom hole pressure less the pressure exerted by a column of gas with the hole void of fluid. This type of calculation is not appropriate for calculation of anticipated pressure for the drilling and completion phases and our recommended change recognizes this difference."

Discussion. The USGS agrees that the suggested revision would go well with the penultimate sentence of the footnote. The sentence was adopted with minor editorial changes. Refer to the final revision of the footnote.

Comments. It was suggested that the following sentence should be added to the footnote: "Any reasonable criteria for calculating anticipated surface pressure known to provide safe operations for a particular company, in combination with appropriate historical design factors, equipment, and operational practices for the type well proposed, shall be deemed acceptable."

It was contended that, "Technology which has proven safe, as well as cost effective for a particular company, should not be arbitrarily set aside."

Discussion. The USGS believes that the type of information suggested by the commenter should be considered by the District Supervisor. The District Supervisor, however, is required to make an engineering judgment on the validity of the calculations used to determine anticipated surface pressure. The second paragraph of subparagraph 3.1 is revised as shown below in italics.

3.1 *General Requirements.*

* * * * *

The design criteria considered for all wells shall be submitted with the Application for Permit to Drill. The criteria to be considered shall include all pertinent factors for well control, such as:

a. Formation fracture gradients.
b. Formation pressure.
c. *Anticipated surface pressure.**
d. Casing setting depths.
e. Permafrost zones.

**Anticipated surface pressure is defined as the surface well pressure which can reasonably be expected to be exerted upon a casing string and its related wellhead equipment. In the calculation of anticipated surface pressure, the lessee shall take into account the drilling, completion, and producing conditions. He shall consider mud densities to be used below various casing strings, fracture gradients of the exposed formations, casing setting depths, total well depth, formation fluid type, and other pertinent conditions. Considerations for calculating anticipated surface pressure may vary for each segment of the well. The lessee shall include as a part of the statement of anticipated surface pressure the calculations used to determine this pressure during the drilling phase and the completion phase, including the anticipated surface pressure used for production string design.*

* * * * *

Comments. One commenter suggested that the first sentence in the penultimate paragraph should be changed to state, "The lessee, its assignee or the lease operator * * *."

Discussion. This suggestion was not adopted because it is not necessary to use the term "assignee," since one who has been assigned an interest in a lease becomes the lessee.

Comments. Another commenter stated that pipe/casing manufacturers produce "numerous proprietary grades of casing" for which there are no American Petroleum Institute (API) Standards. It was further stated that excessive paperwork would be eliminated if each manufacturer of proprietary grade casing file their specifications with each District Supervisor.

Discussion. The USGS agrees with this proposal. Accordingly, the sentence in the fourth paragraph was changed as follows: "If casing to be used is not fabricated to API Standards, the yield strengths of the casing shall be included on the Application for Permit to Drill (Form 9–331C), provided these specifications are not on file with the USGS."

Comments. A commenter recommended that item "d" be amended to add: "A±25—foot tolerance shall be allowed for casing and drill depth requirements." It was contended that: "casing joint lengths and hole fill require some tolerance to meet a specified depth limit.

Discussion. This change was not adopted. Exceptions to the casing setting depth may be authorized by the District Supervisor if evidence supporting the need for such exceptions is presented.

Comments. The title of paragraph 3.1e should be "Abnormally Pressured Zones" and not "Permafrost Zones."

Discussion. This was a typographical error in the June 13, 1979 (44 FR 34062) version of the Order. There is no subparagraph 3.1e. Item "e. Permafrost Zones," is the last item in the list of pertinent factors for well control. The information printed after "e. Permafrost Zones," was intended to be a separate paragraph of subparagraph 3.1.

Comments. One commenter stated that the last paragraph of the June 13, 1979 (44 FR 34062) version was not clear and needed clarification. Another commenter recommended this paragraph be deleted. It was stated, "This requirement has been excerpted from the Prudhoe Bay field rules and is applicable to a permafrost region 2,000 feet thick and 20-year, 50-foot radius thaw under 190°F producing conditions. At this time only 13⅜-inch, 72-pound/foot, N–80 Buttress casing has been tested and demonstrated capable of performing within the specification. In exploratory drilling, and floating drilling in particular, surface casing will normally consist of 16- or 20-inch casing and drilling activities will last about 6 months. It is unknown whether 16- and 20-inch casing can meet the requirement and, indeed, should not be required, since the thaw which would occur over the short period of time and lower temperature drilling activity would be minimal. Specific casing requirements such as those proposed should be included in field rules when development drilling begins as provided for in Section 10 of Order No. 2."

Discussion. The USGS is in general agreement with the rationale presented in this comment. All proposed casing design strings will be reviewed on an individual basis when submitted on the Application for Permit to Drill (Form 9–331C). Therefore, this paragraph was deleted.

Subparagraph 3.2

Comments. It was suggested that the last sentence be changed to add the phrase "with a larger diameter bit than outside diameter of the casing," be inserted following the word "drilled," and before the word "the."

Discussion. It is not believed necessary to include this phrase, since, when any hole is drilled to be cased, the

casing outside diameter must be smaller than the bit.

Subparagraph 3.3.1

Comments. It was suggested the fourth sentence in the first paragraph be revised by changing the word "exact" to "approximate." Another suggestion stated the following sentence should be added to the first paragraph: "Exceptions to the above casing setting depth restraints may be authorized by the District Supervisor if evidence supporting the need for such exceptions is presented by the operator." It was contended that, "As deeper waters are reached, the fracture gradient is reduced with water depth and these current depths may not permit circulation to the surface, i.e. fracture gradient insufficient to support a column of liquid. Casing setting depth exceptions may be required to ensure the safety of operations."

Discussion. Proposed casing programs are to be submitted with the Application for Permit to Drill. Actual well conditions, depth of prospective zones, and other considerations may justify changes in casing setting depth(s), subject to approval by the DCM, Offshore Field Operations. The word "exact" was deleted.

Subparagraph 3.3.2

Comments. It was suggested that the last part of the first sentence be changed from "up to the top of the casing" to "back to the ocean floor."

Discussion. It was recognized that the cement fill requirement should provide for conductor casing set on artificial islands and conductor casing set from floating drilling rigs. Therefore, the subparagraph was revised as indicated below:

3.3.2 *Conductor Casing Cementing Requirements.*

3.3.2.1 *Drilling from Artificial Islands.* When drilling from artificial islands, conductor casing shall be cemented with a quantity of Cement sufficient to fill the calculated annular space back to the surface. cement fill to surface shall be verified by the observation of cement returns. Upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment.

3.3.2.2. *Drilling from Floating Drilling Rigs.* When drilling from floating drilling rigs, conductor casing shall be cemented with a quantity of cement sufficient to fill the calculated annular space up to the top of the casing. Cement fill to the top of the casing shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible or possible, the method of verifying the cement fill shall be approved by the District Supervisor. Upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment.

Comments. It was observed that, "the suggested change in paragraph 3.1 for removal of cement to the mudline hanger applies to paragraph 3.3.2 as well. It is necessary to remove the cement to the mudline hanger assemblies in order to facilitate the operation of mudline suspension equipment and to permit temporary abandonment and re-entry of wells."

Discussion. The USGS agrees with this comment. The following sentence was added to subparagraph 3.3.2.1 and 3.3.2.2: "Upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment."

Subparagraph 3.3.3

Comments. It was suggested that the following sentence be added after the first sentence: "For floating drilling operations that use a one-stack BOP system, a lesser volume of cement is permissible to prevent sealing the annular space between the conductor casing and surface casing." It was contended that: "Measurements to test the seal between the surface and conductor casing are difficult to register when all variables on a floating rig are considered.

"If the surface-conductor casing annulus is sealed at the bottom when using a one-stack subsea BOP system, the subsea casing hanger packoff sealing this annulus cannot be effectively pressures tested without bursting of the conductor casing each time the BOP's are tested to pressure exceeding the collapse pressure of the casing. With some formation exposed below the conductor pipe, the formation should break down before collapse of the surface pipe or burst of the conductor pipe, if a leak occurs in the sealing arrangement."

Discussion. The following statement was adopted: "For floating drilling operations that use a one-stack BOP system, a lesser volume of cement is permissible to prevent sealing the annular space between the conductor casing and surface casing, when approved by the District supervisor. Any annular space open to the drilled hole must be sealed in accordance with the requirements in Order No. 3 upon abandonment."

Subparagraph 3.4

Comments. It was suggested that the fourth sentence be deleted, which states: "Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight."

It was contended that: "Formation fracture strength (in shale) often increases over a period of time with exposure to mud filtrate. Therefore, it is not possible in many cases to test a casing shoe soon after drilling out as high as needed to reach a given mud weight objective. Subsequent (and progressively higher) formation tests are not desirable either, since some amount of 'new hole' is always exposed and a fracture if initiated in a long open-hole section is difficult or impossible to repair without running more casing. Also, testing to 'leak-off' or otherwise inadvertently initiating a borehole fracture can limit the initial (undisturbed) strength of the borehole."

Discussion. This suggestion was not adopted; however, this sentence was changed to the following: "Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as approved by the District Supervisor." The USGS considers the data of formation leak-off or testing to an equivalent mud weight a necessary procedure in wildcat or exploratory wells. Once these data are adequately developed in a given field, it would not be required on each well.

Subparagraph 3.5

Comments. No comment received.

Discussion. A sentence was added to provide for slotted liner and open hole completions.

Subparagraph 3.6

Comments. It was suggested that the word "prolonged" be inserted before the word "unscheduled" in the first sentence in the paragraph following the table. Another commenter suggested that the phrase "that result in redrilling of the entire open hole interval" be inserted after the second use of "operation" in the third line.

Discussion. The USGS is in general agreement with these comments. This paragraph has been rewritten as follows: "In the event of prolonged drill pipe operations which could cause damage to the casing, the casing shall be pressure tested, calipered, or otherwise

evaluated, as approved by the District Supervisor."

Comments. It was suggested that the fourth paragraph be revised in the first sentence to delete "addition to" and insert "lieu of." Also, in the first sentence, delete "sufficient time must elapse" and insert "the waiting time need not exceed the time required." It was contended that: "Industry experience over the past several years shows that there is no reasonable necessity to wait on cement any longer than the time necessary to reach a compressive strength of 500 psi. Cement can be designed and pretested to reach this strength in a minimum time, taking into account bottom hole temperature."

Discussion. These suggestions were not adopted. There are a large number of cement types (slurries) the lessee may elect to use, depending on well depth, temperature, and other well conditions. Cement setting time varies considerably, depending on the percent of bentonite, calcium chloride, or other additives (or retarders) used. It is believed that the 8- and 12-hour waiting time requirements are reasonable.

Comments. Another commenter suggested that: "The second to last paragraph should be deleted or reworded to state that the compressive strength of the bottom 500 feet of cement should be at least that of the formation in which it is set." It was contended that: "On conductor and surface casing cement jobs, the slurry composition is often modified to prevent loss of circulation. This modification precludes development of 500 psi compressive strengths; however, this is insignificant as the surrounding formations generally have less than 100 psi compressive strength."

Discussion. The suggestion was not adopted. Surface casing is commonly set at depths where formation compressive strengths substantially exceed 100 psi.

Comments. It was suggested that in paragraph 4, the 502 feet of annular cement fill be changed to 100 feet. It was stated that there will be excessive waiting on cement time on conductor casing where lightweight, low fluid loss cement must be used in the upper portion of the annulus to prevent lost circulation.

Discussion. The suggestion was not adopted. It is believed that only 100 feet of cement with a compressive strength of 500 psi does not provide integrity to the total cement column, sufficient to resume drilling operations.

Paragraph 4

Comments. One commenter stated, "It is felt that the maximum individual inclination survey limit of 6 degrees is too restrictive and that the limit of 3 degrees for average inclination is sufficiently limiting. It is suggested that the maximum individual inclination survey limit of 6 degrees be dropped." Another commenter suggested that this paragraph be revised to require that: "* * * well will be considered directional if any one survey exceeds 6° and overall average angle exceeds 3°."

Another commenter suggested that the first sentence in the last paragraph be revised by inserting the phrase "If directional at that depth" after "surface casing." It was further suggested: "Insert a second sentence, Dipmeter directional data is an acceptable substitution for directional surveys." In the present third sentence, insert the phrase "if directional at this depth or below surface casing if vertical" after "structural casing."

It was contended that: "For most drilling cases, unless the well is intended to be directional, shallower than the surface casing setting depth, the well will be virtually vertical (1° inclination), and surveys above surface casing depth on vertical wells would serve no useful purpose."

Discussion. It is agreed that a maximum individual inclination survey limit of 6 degrees can be too restrictive. Therefore, this requirement was deleted.

The USGS is concerned with maintenance of leaseline and other spacing requirements; however, the USGS is also concerned as to the location of the bottom of the hole throughout the drilling of the well to total depth.

Dipmeter directional data are acceptable; therefore, the last sentence in paragraph 4 was added, as follows: "A composite dipmeter directional survey, including a listing of the directionally computed inclinations and azimuths on a well classified as vertical, will be acceptable as fulfilling the applicable requirements of this paragraph."

It is not agreed that directional surveys should start below surface casing, since this casing is permitted to be set as deep as 4,500 feet. Hole deviation may become substantial at this depth under certain drilling conditions.

Subparagraph 5.1.1

Comments. Several commenters suggested that the term "maximum anticipated surface pressure" be changed to "anticipated surface pressure." Another commenter suggested that the phrase "maximum burst load" be used. Some of the rationales submitted in support of "anticipated surface pressure" are quoted as follows: "Use of 'maximum anticipated surface pressure' as defined by the USGS on page 29263, FR May 18, 1979, in this context would require use of equipment that is not available. (The definition allows for consideration of a gas filled wellbore.)"

"Casing design requirements and bit size restriction through high pressure BOP's would be all but impossible to live with. In addition, the capability of shutting in a well and reachieving primary well control by circulating under the 'maximum anticipated' pressure is also only a remote possibility."

"The anticipated surface pressure shall consider all pertinent factors for well control, such as (a) Formation Pressure, (b) Formation Fracture Gradients, (c) Mud Densities, (d) Casing Setting Depths."

One commenter defined anticipated surface pressure as follows: "Anticipated surface pressure is defined as the surface well pressure to be exposed to a casing string and its related wellhead equipment. Anticipated surface pressure will take into account the anticipated drilling, completion and producing conditions. It will consider mud densities to be used below various casing strings, fracture gradients of the exposed formations, casing setting depths, total well depth, formation fluid type and other pertinent conditions. Considerations for anticipated surface pressure will vary for each segment of the well."

Discussion. The USGS has analyzed the rationales submitted in support of the phrase "anticipated surface pressure." The commenter's suggestion that "anticipated surface pressure" be used instead of "maximum anticipated surface pressure" was adopted. The content of the commenter's definition of anticipated surface pressure was also adopted, with modification, as stated in the discussion of Subparagraph 3.1, *General Requirements.*

On the Application for Permit to Drill, the lessee shall include anticipated surface pressures at all casing setting depths, and at total depth. the calculations and rationales to substantiate the stated pressures shall also be included. Refer to the discussion of subparagraph 3.1.

Comments. The May 18, 1979 (44 FR 29271) version of the Orders for the four active regions and the June 13, 1979 (44 FR 34064) proposed Arctic OCS Orders contained the following caveat in subparagraph 5.1.1., "except that the working pressure of the annular preventer need not exceed 34,475 kPa (5000 psi)." The caveat was deleted from the final version of Order No. 2 for the

active regions and published on December 21, 1979 (44 FR 76226). Several commenters objected to the deletion of this exception for the following reasons:

1. The deletion was made without a solicitation for comments.

2. A 10,000-psi, 13⅝-inch annular preventer costs $83,000, and larger six 10,000-psi working pressure annular preventers are not available.

3. "The operational need, use, and justification for this equipment is very questionable."

Due to the larger volume of comments received on the deletion, a proposed revision of the requirement was published on April 10, 1980 (45 FR 24715) and interested parties were invited to attend a public meeting at the USGS National Center in Reston, Virginia on May 20, 1980. It was the concensus of opinion that the caveat should be reinstated in the subparagraph. One commenter suggested that a qualifying phrase such as, "If, upon review of an applicant's request for permit to drill, the District Supervisor determines that the blowout preventer equipment proposed for use in not adequate, he may require equipment rated to higher pressures," should be added.

Several commenters stated that they limit the use of annular preventers to controlling pressures in the range of 2,000 to 3,500 psi. This limitation is accomplished through the use of prudent well-control procedures.

Discussion. After considering all comments, the USGS has revised subparagraph 5.1.1, as indicated below in italics. It should be noted that the first sentence of the second paragraph of the former subparagraph 5.1.1 was deleted. The deleted sentence was rendered redundant by the revisions of subparagraph 3.1.

5.5.1 *BOP Equipment.* Blowout preventer equipment shall consist of an annular preventer and specified number of ram-type preventers. The pipe rams shall be of proper size to fit the drill pipe in use. The working pressure of any blowout preventer shall exceed the anticipated surface pressure to which it may be subjected, *except that the working pressure of the annular preventer need not exceed 34,475 kPa (5000 psi), unless a higher working pressure is required by the District Supervisor. When the anticipated surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with the Application for Permit to Drill a well-control procedure which indicates how the annular preventer will be utilized and the pressure limitations which will be applied during each mode of pressure control.*

All blowout-preventer systems shall be equipped with:

* * * * *

Subparagraph 5.1.1g

Comments. It was suggested that the subparagraph 5.1.1g be revised to provide for the use of flexible steel hose and hammer unions.

Discussion. The USGS agrees that the use of flexible steel hoses and hammer unions is common industry practice, and has adopted the suggestion. This equipment is acceptable provided the working pressure ratings are equal to or exceed the other pressure fittings in the choke manifold. It should be noted that the adjective "maximum" was deleted from the phrase "maximum anticipated pressure," in accordance with the rationales presented in the discussions of subparagraphs 3.1 and 5.1.1.

Comments. It was proposed that the following sentence be added to subparagraph 5.1.1g: "Equipment downstream of the choke need not meet this pressure requirement."

Discussion. This proposal was not adopted, since API RP 53 provides for this.

Subparagraph 5.2, Note 5 and 5.3, Note 2

Comments. In the May 16, 1979 (44 FR 29271) and June 13, 1979 (44 FR 34064) versions of Order No. 2, Note No. 5 of subparagraph 5.2, *Subsea BOP Requirements,* was stated as follows:

"—5. When a tapered drill string is in use, the BOP stack shall be equipped with pipe rams to fit both sizes of drill pipe."

In December 21, 1979 (44 FR 76227) version of the Order, the Note stated:

"—5. When a tapered drill string is in use, the BOP stack shall be equipped with two (2) sets of pipe rams for the larger size string and one (1) set for the smaller size string of drill pipe."

The same revision was incorporated into Note No. 2 of subparagraph 5.3, *Surface BOP Requirements.* Several commenters objected to these revisions for the following reasons:

1. The revision was incorporated without a solicitation for comments.

2. "To add one additional set of pipe rams and all appurtenances to a surface stack of 13⅝" or larger size will cost over $100,000. For a subsea stack, the changes are much more significant and the overall cost to add a third set of pipe rams would be over $250,000."

3. "Tapered drill strings have previously been successfully employed with one set of rams for each size of drill pipe. Therefore, this requirement is not necessary or reasonable."

Discussion. The USGS's rationale for these revisions was presented in the Notice on April 10, 1980 (45 FR 24714) as follows:

"The intent of the requirement for two sets of pipe rams for use with a constant diameter drill string is to allow the option of using ram-to-ram stripping or ram-to-annular stripping to enter the hole under pressure. This procedure is a commonly accepted industry practice; therefore, the second set of pipe rams is considered a minimum requirement for a constant diameter drill string.

"Regardless of the drilling string configuration, it is generally considered not to be a safe or acceptable practice to operate with only one set of rams for the major pipe string, because during a stripping operation, with only one set of pipe rams, the annular preventer would have to be relied on to accomlish the operation. Morever, should the pack-off elements fail in the annular preventer, the stripping operation could not be acomplished without a set of backup pipe ram. When a tapered drill string is used, most of the pipe would consist of the larger diameter, and a blowout while making a trip would be far less likely to occur with the smaller size pipe within the stack. In the event that a kick should occur with the smaller size pipe within the stack, it would be necessary to use the annular preventers for the stripping operation; however, the use of the annular preventer could be limited to the number of smaller diameter joints to be stripped to place the larger diameter within the stack."

Comments were also solicited on the above rationale at a public meeting at the USGS National Center in Reston, Virginia, May 20, 1980. The comments received as a result of the **Federal Register** solicitation and the public meeting are addressed below.

Comments. The Majority of the commenters objected to the requirements for the third set of pipe rams when a tapered drill string is in use.

Three commenters contended that if the blowout-preventer stack were arranged with the smaller pipe rams between the larger pipe rams and the blind rams, either the smaller or larger drill pipe rams located below the drilling spool could be closed, and the blind rams could then be replaced with a smaller or larger pipe ram if a redundant ram is considered necessary for a long term well-control operation. Another option would be to replace the small pipe rams with large pipe rams for large ram-ro-large ram stripping.

Discussion. The USGS does not consider these suggestions as viable alternatives. In the case of the surface blowout-preventer stack, it appears that changing rams with the lower portion of

the stack under pressure would be an extremely hazardous operation. Neither commenter indicated that they would attempt such an operation with a subsea blowout-preventer stack. It would appear that with a subsea blowout-preventer stack this operation would be impossible or prohibitive from the standpoint of personnel safety. Furthermore, the last line of defense, i.e., closing the blind shear rams, shearing the pipe, and moving off location, is forever lost whem the blind shear rams are removed. Another alternative to the third set of pipe rams is suggested in the following comment.

Comments. One commenter suggested the following alterative for the third set of pipe rams:

"The objection that the addition of one set of pipe rams to a surface stack will cost over $100,000 and to a subsea stack, over $250,000, assumes that one blowout-preventer must be added to existing stacks to comply with Order No. 2. However, by simply replacing one set of 5" pipe rams with one set of 2⅞" through 5" variable bore rams at a cost of about $25,000, the number of preventers in existing subsea and surface stacks is sufficient to comply with Order No. 2.

"Variable bore rams seal on a range of pipe sizes, i.e., 2⅞" through 5" or 3½" through 7". In a three ram surface BOP stack, blind/shear or lind rams may be installed in the upper ram cavity, 2⅞" through 5" variable bore rams in the middle cavity, and 5" in the lower cavity. Middle and lower pipe rams can then be used to seal on the major or 5" pipe string and the middle rams used to seal on the smaller size pipe. Indeed, by using variable bore rams in both pipe ram cavities, two ram preventers would provide double protection for both pipe sizes of a tapered drill string. Drill pipe can be suspended on variable bore ram 2⅞" through 5" in the same manner as on 5" pipe rams."

Discussion. The USGS reaffirms the rationale contained in the Notice of April 10, 1980 (44 FR 24714). However, as a result of comments received at the public meeting on May 20, 1980, and subsequent comments, it was recognized that certain optional alternative requirements should be incorporated for subsea and surface BOP stacks. therefore, the requirements for subsea and surface BOP stacks are revised as indicated below. Lessees should plan to use a three pipe ram stack arrangement when a tapered drill string is anticipated for use. In the event of an unplanned requirement for a tapered drill string, or when there are mechanical or physical restraints, the revised requirements provide optional alternatives.

It should be noted that item "d" of subparagraph 5.2, and item "e" of subparagraph 5.3 provide the same redundancy as item "a" of subparagraphs 5.2 and 5.3, and that item "e" of subparagraph 5.2 and item "f" of subparagraph 5.3 provide the same redundancy as item "c" of subparagraphs 5.2 and 5.3. It should also be noted that item "d" of subparagraph 5.3 is not allowed as an option for subsea BOP stacks under subpargaraph 5.2, because picking up a crossover sub and switching to the large size pipe when a well control problem occurs with the smaller pipe within the stack, is not a viable option with a subsea stack in deep water. With a subsea stack having only two sets of rams for the larger size pipe, the only course of pipe action with the smaller size pipe within the stack during a blowout might be to shear the smaller pipe. We believe that operating in this mode should be an exception to approved practice and, therefore, should only be allowed under exceptional circumstances through the departure procedure; furthermore, the majority of subsea stacks have sufficient cavities to provide redundant pipe rams, and the "last ditch" option of shearing the pipe is always available with subsea stacks.

5.2 *Subsea BOP Requirements*

* * * * *

—5. When a tapered drill string is in use, the BOP stack shall be equipped with one of the following pipe ram configurations:

a. Two (2) sets of pipe rams for the larger size string and one (1) set for the smaller size string of drill pipe.

b. Two (2) sets of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

c. Two (2) sets of variable bore pipe rams to fit both sizes of pipe.

d. One (1) set of pipe rams for the larger size string, and one (1) set of variable bore pipe rams to fit both sizes of pipe.

e. One (1) set of pipe rams for the larger size string and one (1) set of pipe rams for the smaller pipe, and one (1) set of variable bore pipe rams to fit both sizes of pipe.

* * * * *

5.3 *Surface BOP Requirements.*

* * * * *

—2. When a tapered drill string is in use, the BOP stack shall be equipped with one of the following pipe ram configuration:

a. Two (2) sets of pipe rams for the larger size string or drill pipe and one (1) set for the smaller sizes string of drill pipe.

b. Two (2) sets of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

c. Two (2) sets of variable bore pipe rams to fit both sizes of pipe.

d. Two (2) sets of pipe rams for the larger size string. The blind ram cavity shall be equipped with blind shear rams and blind ram actuator shall be converted to operate the blind shear rams. A crossover sub to the larger size pipe shall be readily available on the rig floor.

e. One (1) set of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

f. One (1) set of pipe rams for the larger string, one (1) set of pipe rams for the smaller pipe, and one (1) set of variable bore pipe rams to fit both sizes of pipe.

* * * * *

Comments. It was proposed that the phrase "or storm packer" be added to last sentence of subparagraph 5.2, after "bridge plug." it was stated, "The inclusion of the term more clearly defines equipment that the operator may select to use depending upon well conditions."

Discussion. This suggestion was adopted.

Subparagraph 5.3

Comments. No comments received.

Discussion. The first item in the table, "Drive or Structural" was amended to add "1–Annular." This requires that when drilling conductor hole (or surface hole), an annular type preventer and a diverter system is required to enhance the safety of this drilling operation.

Comments. It was suggested that Note 1 be revised to add the following at the end of the paragraph: "The flowpath from the BOP to the branch point of diverter lines in new systems shall have a minimum internal diameter of 15 centimeters (6 inches)." It was contended, "For clarification that only one flowpath is required from the BOP to the branch point."

Discussion. This suggestion was adopted for clarity.

Subparagraph 5.4.2

Comments. It was stated that the second sentence reads: "This program shall include all known pertinent information, including * * *, a schematic diagram indicating the equipment to be installed from the rotary table to the proposed conductor-casing seat, and * * *" It was recommended the schematic diagram

requirement be deleted, since, "* * * the riser is not used, there will be no equipment to show in a diagram."

Discussion. This is true if the marine riser cannot be used to drill conductor holes. However, some conductor holes are drilled with a riser equipped with a dump value, which permits sea floor diversion of returns. In these cases, a schematic is required.

Subparagraph 5.7

Comments. No comments received.

Discussion. It is considered necessary that all BOP tests should be recorded. Therefore, the following sentence was added: "All BOP tests shall be recorded in the driller's report."

Subparagraph 5.7.1c

Comments. Several commenters agreed with the proposed revision of subparagraph 5.7.1, Item "c", proposed in the Notice on April 10, 1980 (45 FR 24715) for the Gulf of Mexico and Pacific Regions only. This revision would require blind and blind shear rams to be tested prior to drilling out after each casing string has been set, instead of requiring these rams to be tested weekly. All of the commenters suggested that the revision should be applicable to all regions of the OCS.

Discussion. As a result of comments received at the public meeting on May 20, 1980, it was concluded that due to the variations in drilling rates for all areas of the OCS, adopting the proposed revision for all regions would result in the blind rams and blind shear rams being tested after a time lapse of one week to two months. Several BOP manufacturers suggested that this frequency would be entirely satisfactory for testing blind and blind shear rams. This contention is based on the fact that the sealing surfaces of blind and blind shear rams are not subjected to as much friction wear as occurs with pipe rams; therefore, the seal life is longer and requires less testing.

The USGS agrees with this contention and has revised the requirements for all regions of the OCS. Since this revision pertains to the frequency of testing, it was recognized that it would be editorially simpler and clearer to revise subparagraph 5.7.1, *BOP Testing Frequency.* Therefore, we revised subparagraphs 5.7.1, 5.7.2, and 5.7.3, as shown below in italics. It should be noted that an additional sentence was inserted after the first sentence of item "c" of subparagraph 5.7.1. This sentence was formerly contained in item "d" of subparagraph 5.7.4. Refer to the discussion of the revsion of subparagraph 5.7.4.

A statement was also added to identify two operations under which tests may be delayed. The added sentence is as follows: "Well operations which prevent testing are stuck drill pipe and pressure control operations."

5.7.1 *BOP Testing Frequency.* Surface and subsea BOP stacks shall be tested as follows:

* * * * *

c. At least once each week, but not exceeding 7 days between tests, alternating between control stations. *If either control system is not functional, further drilling operations shall be suspended until that system becomes operable.* A period of more than 7 days between blowout-preventer tests *is allowed when well operations prevent testing and remedial efforts are being performed, provided the tests will be conducted as soon as possible before normal operations resume, and the reason for postponing testing is entered into the report. Well operations which prevent testing are stuck drilling pipe and pressure-control operations.* Testing shall be at staggered intervals to allow each drilling crew to operate the equipment.

The weekly test is not required for blind and blind shear rams. These rams need only be tested prior to drilling out after each casing string has been set.

* * * * *

5.7.2. *Pressure Testing Surface BOP Systems.* The penultimate sentence of subparagraph 5.7.2. is deleted. This sentence is rendered redundant by the revision of subparagraph 5.7.1., item "c."

5.7.3. *Pressure Testing Subsea BOP Systems.* The last sentence of subparagraph 5.7.3. is deleted. This sentence is rendered redundant by the revision of subparagraph 5.7.1, item "c."

Subparagraph 5.7.2

Comments. No comments received.

Discussion. The phrase "including the choke manifold" was added to the first sentence. This is to clarify that the choke manifold is to be included in the "related control equipment."

Comments. Several commenters recommended that the last sentence be deleted. It was contended that: "The testing of the smaller pipe rams with this frequency and while off bottom with open hole is a hazardous exposure and should be avoided. The small pipe rams should be tested with the same frequency and in the same manner with the other ram-type BOP's."

Discussion. The USGS agrees with the above rationale, and has deleted the last sentence.

Comments. Another commenter is quoted as follows: *"Section 5.* (Blowout-Preventer (BOP) Equipment Requirements.) This section appears flawed with a serious inconsistency. Although Section 5.1.1 requires 'the working pressure of any blowout preventer shall exceed the maximum-anticipated surface pressure to which it may be subjected,' Section 5.7.2, *Pressure Testing Surface BOP Systems* reads: 'Ram-type BOP's and related control equipment shall be tested at the maximum-anticipated surface pressure or at 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. The annular type BOP shall be tested at 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser.'

"Therefore, if 70 percent of the minimum internal yield pressure of the casing is less that the maximum anticipated surface pressure at a ram-type BOP, if a blowout occurred at maximum pressure, the BOP would not have been tested for that great a pressure and failure might ensue. Similarly, at best, the annular BOP will be tested at 70 percent of the maximum anticipated surface pressure. This minimum testing cannot assure proper functioning of the equipment at full load."

Discussion. The commenter incorrectly quoted the second sentence of subparagraph 5.7.2. The phrase, "of its rated working pressure or 70 percent" was deleted in the comment. This deletion changed the meaning of the second sentence concerning annular type BOP testing. Testing annular type BOP's at 70 percent of the anticipated surface pressure is not the intent, as stated in the penultimate sentence of the commenter. The annular type preventers are to be tested at 70 percent of their rated working pressure, or 70 percent of the internal yield pressure of the casing, whichever is lesser. Casing strings are designed with the minimum internal yield pressure greater than the anticipated surface pressure at their setting depths.

In BOP testing, the limiting factor is the minimum internal yield pressure of the casing. The safety factor of 70 percent is used to protect the casing string from pressures exceeding the internal yield, in the event of a test plug failure. In all cases, BOP's are factory tested to pressures greater than their working pressure.

It is not practical to field test BOP's above their working pressure, which could be greater than the internal yield pressure of the casing.

Subparagraph 5.7.4

Comments. Several commenters objected to the "partial actuation"

requirement of this subparagraph when tapered drill strings are in use, because there is no reliable way to assure that the smaller size rams would not close completely on the pipe and thereby damage the rams and the pipe.

Other commenters objected to the frequency of the daily and every other day requirement for the actuation of surface and subsea BOP pipe rams. At the public meeting on May 20, 1980, several BOP manufacturers expressed their opinion that the actuation of rams required during the weekly pressure test is adequate to assure the reliablility of the BOP stack. It was contended that daily and every other day action of the rams could result in unnecessary "wear and tear."

Discussion. In consideration of all of the comments, the USGS has reevaluated the rationale for the actuation tests and has replaced the original subparagraphs 5.7.4 and 5.7.5 with a new subparagraph 5.7.4, *Actuation of Auxiliary Well-Control Equipment,* as indicated below.

It should be noted that the content of item "d" of the deleted original subparagraph was incorporated into item "c" of the revised subparagraph 5.7.1. This sentence was modified to state, "If either control system is not functional, further drilling operations shall be suspended until that system becomes operable." It is mandatory to be able to control the BOPs from either station at all times.

5.7.4 *Actuation of Auxiliary Well-Controll Equipment.* In conjunction with the weekly pressure test of surface and subsea BOP systems, auxiliary well-control equipment, such as choke manifold valves, kelly cocks, and drill pipe safety valves, shall be actuated. Casing safety valves shall be actuated prior to running casing.

Subparagraph 5.8

Comments. Several commenters objected to the requirement that all BOP systems, marine risers, and associated equipment shall be inspected and maintained in accordance with the manufacturers' recommended procedures.

Discussion. The USGS believes this comment has merit and has revised subparagraph 5.8, as indicated below in italics.

Comments. A commenter proposed that the following two sentences be added: "When using the underwater television equipment for other purposes, it is expected that the BOP stack and marine riser systems be inspected. Deployment of the television equipment for the express purpose of inspection of the stack and riser systems needs to be done only weekly at the time of performance of the subsea BOP tests."

Discussion. This proposal was not adopted. The USGS believes that daily inpsection is necessary in order to verify the integrity of the BOP stack and marine riser.

5.8 *Inspection and Maintenance.* All BOP systems, marine risers, and associated equipment shall be inspected and maintained *to assure that the equipment will function properly. The manufacturers' recommended inspection and maintenance procedures are acceptable as guidelines in complying with this requirement.* The BOP systems and marine risers shall be visually inspected at least one each day, if the weather and sea conditions permit the inspection. Inspection of subsea installations may be accomplished by the use of television equipment.

Subparagraph 5.9

Comments. A commenter suggested that a phrase in the last sentence be changed from "at any time" to "any reasonable time." Another commenter recommended that the following phrase be added to the last sentence: "after consulting with the operator's senior representative present." It was contended that: "During certain times in drilling operations, a BOP drill would be hazardous. Consultation with operator's representative would avoid such hazards."

Discussion. The USGS agrees in part with these suggestions and has revised the requirement to state, "after notifying *and consulting with* the lessee's senior representative present." We believe that the phrase *"and consulting with"* provides a safeguard against a request for drill at an ill-advised time, because the lessee's senior representative would advise the USGS representative of any hazardous well conditions which would prohibit the test. We believe the USGS representative should have the prerogative of requesting an unscheduled BOP drill in order to retain the element of surprise as a test of the state of readiness of the drilling crew and equipment.

It is considered necessary that all BOP drills should be recorded. Therefore, the following sentence was added: "All BOP drills shall be recorded in the driller's report."

Paragraph 6

Comments. It was suggested that the first sentence of the second paragraph be changed to read: "Mud temperatures shall be controlled to minimize heat loss to and thawing of the permafrost, which can result in serious well problems while drilling through the permafrost."

Also it was suggested that the second and third sentences in the same paragraph be modified to permit continuance of drilling without having to cool the muds once the hydrate zones have been duly protected.

Discussion. These suggestions were adopted, and the second paragraph was modified to read: "Mud temperatures shall be controlled to minimize heat loss to the permafrost and to mimimize thawing of the permafrost, which can result in serious well problems while drilling through the permafrost. To insure maximum safety, hydrate zones shall be anticipated and diagnosed quickly, and drilled using the latest state-of-the-art methods. Provided that the hydrate zones are adequately protected, drilling can continue on a site specific basis without the need to control the temperature of the mud thereafter."

Subparagraph 6.1

Comments. It was contended that the requirement for circulating bottoms up prior to starting out of the hole "* * * should be tempered to fit well conditions."

Discussion. In our opinion, the subparagraph is "* * * tempered to fit well conditions" since the subparagraph requires "* * * either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, *or proper documentation in the driller's report prior to pulling the pipe as follows."* Items "a," "b," and "c" then list conditions which are required to be documented in the driller's log in lieu of circulating bottoms up.

Comments. It was contended that item "b" should be tempered to allow some reasonable difference in the weight of returning mud and the weight of mud entering the hole. One commenter suggested an allowable mud weight difference of 0.2 pound per gallon, and another commenter suggested an allowable difference of 1 percent.

Discussion. The USGS agrees with this contention and has revised subparagraph 6.1, item "b," as follows:

6.1 *Mud Control*

* * * * *

b. The weight of the returning mud is essentially the same as the weight of the mud entering the hole. In the event that the returning mud is lighter than the entering mud by weight differential equal to or greater than 0.2 pound per gallon, the mud shall be circulated until the annular volume is displaced, and the mud properties shall be checked for the influx of gas or liquid.

* * * * *

Comment. One commenter suggested that the requirement to post a maximum pressure to be contained under a blowout preventer before controlling excess pressure by bleeding through the choke is inconsistent with good well control philosophy.

Discussion. This suggestion has merit and the requirement was modified to read: "The maximum pressure which can be tolerated on each casing string shall be posted near the driller's control console."

Comments. A commenter suggested that the term "vacuum-type" should be deleted from the penultimate paragraph. It was further stated that: "To define vacuum type only precludes any advancements on new equipment for this purpose. It would also require removal of existing equipment."

Discussion. The USGS agrees, and the term, "an operable gas separator," was adopted.

Subparagraph 6.2a

Comments. A commenter proposed the following: "Section 6.2a provides for monitoring of mud levels and requires visual and audio warning devices. The Gulf of Alaska Operations Orders specified numerical maximum changes beyond which warning devices would be triggered. We suggest that such a provision be added to this section."

Discussion. The sensitivity of the pit volume measuring devices should be custom designed to provide the maximum possible sensitivity, considering the type of vessel or structure. Therefore, limitations should not be placed on these indicators.

Subparagraph 6.3

Comments. It was the view of some commenters that subparagraphs 6.3a and 6.3b requrie excessive mud quantities which may exceed certain rig mud storage capacity. Another commenter stated that: "The requirement should include only that which is common practice in the offshore, i.e., to keep weighting material and to have replacement for usage within several hours of reach. Material storage volume requirements should be specified as: 'the quantity required to weight up the system 1 ppg.' " Another opinion stated that: "a very simple and practical approach to this subject is to require a minimum material inventory of the amount necessary to increase the weight of the active mud system by 1 pound/gallon."

Discussion. The USGS agrees that some rig mud storage capacity would be exceeded under the requirements of subparagraphs 6.3a and 6.3b; therefore, the requirements of subparagraphs 6.3a and 6.3b were deleted. Since the Order requires a table of mud quantities versus well depth to be submitted with the Application for Permit to Drill, the District Supervisor will evaluate the criteria used to determine these quantities.

The second paragraph clearly provides for adjustment where the required quantities exceed rig storage capacity. This paragraph states: "When the mud quantity required exceeds the storage capacity of the drilling facility, the lessee shall maintain maximum mud inventories and must receive approval from the District Supervisor of the lessee's plans to resupply mud inventories in the event of an emergency. The plan shall include an estimate of the time required for delivery of the mud supplies."

Suparagraph 6.4a

Comments. One commenter stated that: "Requiring what appears to be continuous high-capacity ventilation will create an enormous heating requirement to keep the mud from freezing in the winter. The requirement should be for ventilation capability which can be activated when necessary and only to the extent required to prevent unsafe concentrations of combustible gas." It was also suggested that: "* * * the sentence be altered to read that 'the enclosed area be ventilated with high capacity mechanical ventilation systems capable of changing the air every two minutes on signal from a gas detector or gas detectors, indicating the presence of gas.' "

Discussion. Addtional comments received in response to the EA resulted in a revision of the subparagraph. Refer to section II of this Notice.

Subparagraph 6.4b

Comment. It was proposed that the following sentence be added: "The negative pressure areas are to be protected with a pressure sensitive alarm."

Discussion. The USGS believes this suggestion has merit, and adopted this statement.

Subparagraph 7.2

Comments. One commenter suggested adding "storm packer" following "bridge plug" in the last sentence.

Discussion. The USGS agrees; "storm packer" was added.

Subparagraph 7.3

Comments. No comments received.

Discussion. The second and third paragraphs were combined for the purpose of clarity. The first sentence of the former third paragraph was changed to read as follows: "In order to maintain qualification, any driller, toolpusher, or operator's representative must successfully complete a USGS-approved refresher course annually and repeat the basic well-control course every 4 years, as described in the provisions of GSS–OCS–T 1."

The phrase: "After December 1, 1979" was deleted, since this date is not applicable to the Arctic Order. This sentence becomes the second sentence in the second paragraph.

Paragraph 8

Comments. No comments received.

Discussion. In the second sentence, the phrase: "Second Edition, June 1979" was changed to "First Edition, February 1976." The Second Edition to the USGS Standard on hydrogen sulfide is currently being developed.

Paragraph 9

Comments. No comments received.

Discussion. It was recognized that there was not a time period stated as to when the lessee should submit a Critical Operations and Curtailment Plan. Therefore, in the second sentence of paragraph 9, the phrase "file with the District Supervisor" was deleted; the phrase "submit for approval with the Exploration Plan or Development and Production Plan" was added.

Subparagraph 9b(4)

Comments. One commenter suggested that ice conditions and hazards be considered under this requirement.

Discussion. Although ice conditions are considered to be a part of oceanographic conditions, for clarity, this suggestion was adopted, and the sentence was revised to read: "known or anticipated meteorological, oceanographic, and ice conditions."

Subparagraph 9c

Comments. It was stated that: "Present wording requires the name of the person with responsibility for safety of drilling operations. We feel very strongly that this should be the title of the person and not a name—thus allowing more flexibility of personnel and is much more practical." Another commenter suggested that the words "* * * at the site * * *" be eliminated and replace with "* * * the person in charge of overall drilling operations * * *." It was also stated that: "The representative 'at the site' does not have overall responsibility for the operation and is subject to change due to work schedule."

Discussion. The USGS does not agree that only a title of the person in charge

should be submitted. Generally, titles within an organization may remain the same, i.e., "Drilling Superintendent" and "Drilling Foreman." In normal operations, and particularly in times of emergencies, it is considered essential that the names corresponding to these positions be known, so that the individual may be contacted. It is agreed that the lessee's representative may not have the "overall responsibility for the operation" at the site. Accordingly, item "c" was revised to read: "The name of the person who has responsibility as the person in charge of overall drilling operations."

Paragraph 10

Comment. No comment received.

Discussion. A new paragraph 11, *Use of Best Available and Safest Technologies (BAST),* was added to incorporate the requirement for the use of BAST in accordance with the OCS Lands Act Amendments of 1978. the subsequent paragraph, *"Departures"* was renumbered.

OCS Order No. 3

General Comments.

Comments. One commenter stated, "The requirements of Proposed Order No. 3, regarding plugging and abandonment, are certainly sufficient. We request, however, that the Proposed Order and the regulations on which the Order is based be amended to require action possibly three days from receipt. the standby costs for a rig alone are considerable and are escalating every day. If action is not rapidly taken on a request to plug and abandon, a very substantial cost will be incurred by the operator for the direct costs associated with the additional rig standby and more costs for services standby. Furthermore, for every day a rig is idle, it takes that much longer to drill the next well."

Discussion. This comment does have merit; however, the USGS does not agree that a time limit, as recommended, should be placed in the Order. We know of no instance in the Gulf of Alaska Region when an unreasonable length of time was taken in approving a plugging and abandonment program. Usually, if a company submits a program with adequate diagrams and information, the Gulf of Alaska Region OCS District Office has the capability and will approve or disapprove the program within a matter of hours.

Paragraph 1

Comments. No comments received.

Discussion. A new paragraph 1, *Application for Approval to Abandon a Well,* was added in accordance with the regulation, 30 CFR 250.92, *Sundry Notices and Reports on Wells.* The subsequent paragraphs were renumbered. In the comments and discussion which follow, the original paragraph numbers are indicated in parentheses.

Subparagraph 2.4.1b (1.4.1b)

Comments. One commenter suggested that subparagraph 2.4.1b (1.4.1b) be reworded to clarify where the cement should be set.

Discussion. The USGS revised this subparagraph for clarification.

Subparagraph 2.8 (1.8)

Comments. Two commenters were concerned that the subparagraph did not allow oil base fluid to be left in the hole. The current use of the oil based arctic gels are believed to be a superior method for insulation and maintenance of casing integrity.

Discussion. The effects of these arctic gels upon the marine environment have not yet been determined. Therefore, each well should be considered on a case-by-case basis, and the environmental effects can be ascertained throughout the exploratory and development process. The subparagraph was changed to reflect this thought.

The USGS provided an additional requirement to use corrosion inhibitors in fluid left adjacent to the permafrost, thereby insuring the integrity of the pipe.

Subparagraph 2.10 (1.10)

Comments. It was suggested that the phrase "and to have a low heat of hydration" be deleted, since it is questionable whether a "high" heat of hydration affects the permafrost when the hole is drilled with warm mud.

Discussion. This suggestin was not adopted. The USGS believes that cement used throughout permafrost zones must have a low heat of hydration so as not to thaw frozen formations. The use of gypsum based cement is a proven successful method of cementing in permafrost zones. The effects of mud in the permafrost zone have been addressed, and according to Order No. 2, paragraph 6, mud temperature must be controlled to minimize heat loss and thawing effects.

Paragraph 3 (2)

Comments. One commenter suggested that subparagraph 2.3 (1.3), *Plugging or Isolating Perforated Intervals,* should be included in the exceptions to temporary abandonment. It was believed that a producible zone would be damaged if subjected to the cement job.

Discussion. This suggestion was not adopted. Since temporary abandonment does not have any time constraints, this type of plugging should be required to prevent migration of fluids. The subparagraph allows for isolation of the zone by setting a bridge plug above the interval as long as the perforations are isolated from the hole below. this method will prevent formation damage.

Comments. It was suggested that subparagraph 2.5 (1.5), *Plugging of Annular Space,* be included in the exceptions to temporary abandonment. If test casing were installed, it would be undesirable to perforate and squeeze before testing other formations.

Discussion. The suggestion was not adopted. We agree that it would be undesirable to perforate and squeeze a test casing string. However, we believe that a request for departure is required to justify a waiver of the requirement for cementing the annular space. A departure of this nature may be approved on a case-by-case basis after consideration of all the risk factors.

It was recognized that the last sentence was only applicable to item "b" of the proposed Order. Therefore, the content of the original item "a" was incorporated as the penultimate sentence. The content of the original item "b" was incorporated into the last sentence.

OCS Order No. 4

Paragraph 1

Comments. Several commenters suggested that an Application for Determination of Well Producibility should be filed at the operator's discretion. The thought was that the application would be a "waste of time" for dry holes, and that the operator would lose competitive advantage by submitting such proprietary data.

Discussion. The USGS believes that the application provides necessary scientific and technical information concerning the geology of OCS leases. The timely submittal of this information is required for the District Supervisor's evaluation of the diligence of the lessee in the development of the lease.

The proprietary nature of all information submitted with the Application for Determination of Well Producibility will be evaluated, in accordance with the OCSLA and the Freedom of Information Act. Data which are determined to be proprietary will not be released.

OCS Order No. 5

Preamble

Comments. A comment pertaining to the submittal of certain information by

the lessees who are designated operators, was received.

Discussion. Refer to the discussion under the heading of "General Comments" at the beginning of section I of this Notice.

Paragraph 1

Comments. One commenter suggested that the requirement for the use of the best available and safest technology (BAST) be specifically stated in this Order.

Discussion. This paragraph was revised to include language requiring the use of BAST.

Paragraph 2

Comments. No comments received.

Discussion. The phrase "or subsequent revisions which the Chief, Conservation Division, has approved for use," was deleted from the first sentence. This phrase is not necessary because under the reorganization of the Conservation Division, representatives of the Deputy Chief, Conservation Division, Offshore Minerals Regulation, participate in the development of the referenced quality assurance standards. The references to specific editions in item "a" and "b" were changed to "latest edition, with all addenda."

The last sentence was revised to eliminate the reference to the dates for compliance. This reference is not necessary, since the effective date of these Orders provides sufficient time for Arctic lessees to be in compliance with the quality assurance requirements when the first surface and subsurface safety valves are installed.

Subparagraph 3.1

Comments. Several commenters stated that: "(1) the requirement that the attendant being at the wellhead is unnecessary if the well is shut-in, (2) at the wellhead can be a dangerous location if operations are being conducted overhead, and (3) the attendant could be more effective if free to move about and monitor overall operations."

Discussion. "At the wellhead" is considered overly restrictive, and attendance is not necessary if the well is shut-in (not open to flow from a hydrocarbon-bearing zone). The subparagraph was revised.

Comments. A commenter who uses a tubular/annular type subsurface-safety device which vents annular gas pressure on wells lifted by electric submersible pumps, requested that this type of safety device be included in the list of acceptable devices. Another commenter suggested that criteria be established for the determination of the capablility of a well to flow.

Discussion. The revised list includes the tubular/annular type subsurface-safety device. The availability of criteria from the District Supervisor toward determination of the capability of a well to flow was noted in the revised subparagraph.

Comments. Another commenter recommended that due to the variable characteristics of permafrost in offshore areas, the setting depth of the subsurface safety device should be approved by the District Supervisor on a case-by-case basis.

Discussion. The recommendation was adopted.

Subparagraphs 3.2.1a. and 3.1.1b

Comments. One commenter claimed that advances in technology have solved earlier problems related to the control lines and connections of surface-controlled subsurface-safety valves (SCSSV's).

Discussion. The primary reasons for requiring subsurface-controlled subsurface-safety valves (SSCSV's) at pressures above 4,000 psi were problems of communication in the control lines and tubing hangers at these higher pressures. A determination was made that these problems have been solved adequately by improvements in technology. The requirement for SSCSV's above 4,000 psi was removed accordingly.

Subparagraph 3.2

Comments. Several commenters suggested that this paragraph be revised to conform to the February 1, 1980, compliance date, as announced on June 13, 1979 (44 FR 34060).

Discussion. The phrase "which are installed on new installations after July 1, 1979," was deleted. This requirement does not apply to the Arctic Order, since all installations will be made in the future.

Comments. Another commenter stated that standards for installation and operation of equipment as outlined in subparagraphs 2a, 2b, 3.2, 3.3, 3.9, 4.2, 4.3c, 4.3e, 5.1.1, 5.1.8, and 5.1.10c should include required differences in installation and operation standards to conform to the three seasonal conditions in the Arctic.

Discussion. In response to this comment and another comment received on the Orders contained in the Appendix of the EA, a new subparagraph 1.1, *Subfreezing Operations,* was added. Refer to the discussion of subparagraph 1.1 in section II of this Notice. Since this new subparagraph requires lessees to submit evidence that *all* production safety systems must be suitable for operations under subfreezing conditions, the references to subfreezing condtions in other subparagraphs in the Order were deleted.

Comments. It was suggested that this subparagraph be revised to allow the use of valves that had been qualified by performance testing to a previous edition of "API Specification for Subsurface Safety Valves," API Spec 14A, during the performance test effectivity.

Discussion. The USGS has revised subparagraph 3.2, indicated below in italics, to allow the use of previous qualified valves for the duration of the 3-year qualification period. These valves must then be requalified to the Fourth Edition of API Spec 14A, as required by section 4.2 of API Spec 14A, if manufacturing is to be continued.

It should be noted that the subparagraph addresses future replacement of subsurface-safety valves and defines the term "replacement."

It should also be noted that the subparagraph was revised to exclude section 6, Appendix A and Appendix J of Specification which addresses the use of the API monogram. A sentence was added to make it clear that the use of the API monogram is optional; whereas, the use of the OCS symbol is mandatory.

Comments. Another commenter expressed agreement with the revision proposed on April 10, 1980 (45 FR 24716), pertaining to subsurface-safety valves and recommended that a similar revision be included for surface-safety valves.

Discussion. The USGS does not intend to revise subparagraph 4.2, *Specification for Wellhead Surface-Safety Valves (SSV),* because these valves are required to conform to API Spec 14D, Third Edition, November 1980. Subsection 4.2 of this document states that "performance testing is not required for SSV equipment other than valves for Class 2 service." Periodic retesting is a requirement of API Spec 14A. There is no retest requirement in API Spec 14D.

3.2 *Specification for Subsurface-Safety Valves.* Surface-controlled and subsurface-controlled-safety valves required by subparagraphs 3.4 and 3.5, *which are installed or replaced,* shall conform to "American Petroleum Institute (API) Specification for Subsurface-Safety Valves," API Spec 14A, Fourth Edition, November 1977, *with the exception of section 6, Appendix A and Appendix J of this specification, except for provisions thereof that are required in sections 1 through 5 of this specification,* or

subsequent revisions which the *Deputy Chief, Conservation Division—Offshore Minerals Regulation,* has approved for use at the time of installation. *The API monogram is optional, whereas the requirement for the OCS symbol is mandatory. A valve qualified to a previous edition of API Spec 14A is acceptable, provided that the valve enters inventory within 3 years of its qualifying performance test date. For purpose of this requirement, the term "replacement" is defined as occurring when that portion of the valve assembly containing the serial number is removed from inventory and a new certified valve is placed in inventory.*

Subparagraph 3.3

Comments. Several commenters suggested that this paragraph be revised to conform to the February 1, 1980, compliance date as announced on June 15, 1979 (44 FR 34650).

Discussion. Subsequent to this **Federal Register** Notice, the latest edition of the American Petroleum Institute Recommended Practice 14B (API RP 14B) was disapproved for use by the Chief, Conservation Division. All references to API RP 14B were removed from this Order.

Subparagraph 3.4

Comments. No comments received.

Discussion. The phrase "After the effective date of this Order" was deleted. Since all installations will be in the future, this phrase is not necessary.

Subparagraph 3.4.1

Comments. One commenter argued that the requirement to test wireline retrievable valves monthly for 3 months after being removed for frequently conducted routine operations results in excessive testing and causes unnecessary wear and possible failure of the valves.

Discussion. The comment about excessive testing leading to possible failure has validity. The paragraph was revised to remove all monthly testing requirements for both wireline and tubing retrievable valves. Also, the reference to API RP 14B was deleted for the reasons stated in the discussion under subparagraph 3.3.

Comments. Another commenter argued that the rate of testing is too infrequent and that frequency should be increased over the life of the devices, since equipment becomes less reliable with age.

Discussion. The performance of subsurface-safety valves is very closely monitored under a formal failure and inventory reporting system as outlined in paragraph 6 of this Order.

Statistical analyses of these data does not suggest that an increase in the testing frequency, over that to be required, would contribute to safety or reliability.

Subparagraph 3.5

Comments. No comments received.

Discussion. The words "or jacket" were deleted, since they are unnecessary and a source of confusion.

Subparagraph 3.5.1

Comments. One commenter suggested that SSCSV's should be tested in place by surface means.

Discussion. There is no known hazard-free and convenient method to flow test a SSCSV for closure in a well.

Subparagraph 3.6

Comments. No comments received.

Discussion. The words "after the date of this Order" were deleted for the same reason stated in subparagraph 3.4. The second sentence was revised to make it clear that the 30 meter setting depth for tubing plugs is applicable to nonpermafrost areas.

Subparagraph 3.7

Comments. No comments received.

Discussion. It was determined that the proper functioning of subsurface safety devices in injection wells is of such importance to warrant the formal, periodic testing program. Therefore, testing requirements were added to the subparagraph.

Subparagraph 3.8

Comments. Several commenters stated that, "(1) at the wellhead can be a dangerous location if operations are being conducted overhead, (2) the attendant could be more effective if free to move about and monitor overall operations, and (3) clarification was needed as to under what conditions attendance at the wellhead is required."

Discussion. "At the wellhead" is considered overly restrictive, and attendance is not necessary if the well is shut-in (not open to flow from a hydrocarbon-bearing zone). The subparagraph was revised.

Comment. One commenter stated, "It is unclear from the description of the subsurface safety device removal process that a second unit was required to be on the platform for immediate replacement of the damaged unit. If this is not standard practice, it should be."

Discussion. The comment has been reviewed and we agree. Subparagraph 3.10 of Order No. 5 already addresses this requirement and we believe it is adequate.

Subparagraph 3.9

Comments. No comments received.

Discussion. The phrase "after the effective date of this Order" was deleted for the same reason stated in subparagraph 3.4.

Subparagraph 3.10

Comments. No comments received.

Discussion. The phrase "and capable of flowing" was added to the first sentence of this subparagraph. This addition was made to clarify that if the well is not capable of flowing, the requirements of subparagraph 3.10 do not apply.

Subparagraph 3.11

Comments. One commenter claimed that the paperwork required to be prepared and maintained offshore is excessive.

Discussion. The USGS is aware of the paperwork burden and constantly searches for methods and places to reduce the load without sacrificing essential information.

Comments. No comments received.

Discussion. It was recognized that a lessee may not have an offshore field office; therefore, a sentence was added to this subparagraph as follows: "If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office."

Subparagraph 3.11a

Comments. It was suggested that, for clarity, the term "design" be qualified as the "manufacturer's design."

Discussion. The suggestion was adopted.

Subparagraph 3.11f

Comments. Commenters remarked that this requirement is unclear and that it is difficult to make accurate verifications of personnel.

Discussion. The subparagraph was revised to require the identity of the person qualified in accordance with subparagraph 5.7.

Subparagraph 3.12

Comments. No comments received.

Discussion. The word "manufacturer" was added to this subparagraph, which is consistent with paragraph 6, *Failure and Inventory Reporting System (FIRS).*

Paragraph 4

Comments. No comments received.

Discussion. The title of this paragraph was revised to include the word "surface." This word was added to clarify that paragraph 4 covers the requirements of surface production safety systems, whereas, paragraph 3

includes the requirements of subsurface safety devices.

Comments. One commenter alleged that the language used in this paragraph is vague and does not assure use of BAST.

Discussion. Paragraph 1 of this Order was revised to require the use of BAST.

Subparagraph 4.2

Comments. No comments received.

Discussion. The phrase "on new installations after July 1, 1979" was deleted for the same reason as discussed in subparagraph 3.4.

It should also be noted that the subparagraph was revised to exclude Appendix A and Appendix J of the Specification which addresses the use of the API monogram. A sentence was added to make it clear that the use of the API monogram is optional; whereas, the use of the OCS symbol is mandatory.

Subparagraph 4.3

Comments. A commenter requested that valves used to vent casing pressure on certain low-pressure wells produced by electric submersible pumps be exempt from certification requirements.

Discussion. These valves used as casing vent valves on wells produced by electric submersible pumps are not considered to be primarily surface safety valves (SSV's) and are, therefore, exempt from the requirements of API RP 14D and certification requirements.

Comments. One commenter suggested, "Safety Analysis Function Evaluation Chart should be supplemented by actual computer simulation of failure. Although more expensive than a chart, a simulation program can test the system logic more thoroughly than a chart and also be used as a training tool and an aid in system design and refinement."

Discussion. Subparagraph 4.3b requires the lessees to submit a schematic flow diagram and related Safety Aanlysis Function Evaluation (SAFE) chart. This chart shall be developed in accordance with the provisions of API RP 14C and the additional requirements of OCS Order No. 5. Since the lessees will be conforming to the requirements of an approved API RP 14C Code, the Chart will be used to meet the requirements of BAST. Also, see discussions of BAST under comments and discussion on subparagraph 2.1.1, *Fitness of Drilling Unit,* of OCS Order No. 2.

Subparagraph 4.3c

Comments. No comments received.

Discussion. The phrase "design pressure" was deleted from the first sentence; the words "maximum-allowable working pressure" were added. This revision was made in order to be consistent with API RP 14E.

Subparagraph 5.1.1

Comments. One commenter remarked that subparagraph 5.1.1 was apparently contradictory to subparagraph 5.1.1d.

Discussion. Subparagraph 5.1.1 was revised to remove the apparent contradiction, by adding the phrase "Unless otherwise qualified for use according to subparagraph 5.1.1d below" to the first sentence.

Subparagraph 5.1.1c

Comments. Two commenters recommended removal of the requirement that the high pressure shut-in sensor be set no higher than 10 percent above the highest operating pressure of the vessel on the grounds that there is no justification for protecting a vessel from pressures below its working pressure and that such a pressure sensor setting would cause nuisance shut-ins.

Discussion. The comments were not accepted, since the margin of safety surrendered is not offset by possible nuisance shut-ins or other adverse effects.

The phrase "by the use of pressure recorders" was added in order to clarify the intent of the requirement for the recording of operating pressure ranges.

Comments. Another commenter noted that some production processes operate at less than 35 kPa (5 psi) and suggested that the activation pressure of low-pfessure sensors on these pressure vessels be approved by the District Supervisor on a case-by-case basis.

Discussion. The suggestion was adopted. The language in the former version of the subparagraph did not adequately cover vessels operating at these low pressures.

Subparagraph 5.1.1d

Comments. No comments received.

Discussion. The phrase "after the effective date of this Order" was deleted in the first sentence for the same reason as the discussion in subparagraph 3.4.

The phrase "prior to placing in service" was added to the second sentence. This clarifies that the lessee has the option of pressure testing the vessel at any location prior to placing the vessel in service.

Subparagraph 5.1.2a

Comments. No comments received.

Discussion. There have been several questions from field personnel as to the interpretation of the first sentence of the subparagraph and the recommendation of Section A1 of API RP 14C. The first sentence was revised to make it clear that the high and low pressure sensors are to be located on the flowline in accordance with *Section A1 and Figure A1* of API RP 14C.

The second sentence was deleted. The requirement for equipment to permit testing of pressure sensors with an external pressure source is stated in subparagraph 5.1.3 of this Order.

Comments. One commenter recommended that the high-pressure flowline sensor may be set at 250 psi above the normal operating pressure of the system to allow for swings in pressure, such as heading.

Discussion. This recommendation was not adopted. The reduction in the level of safety by such a broad license is not offset by the efforts involved in resetting pilots or using two sets of pilots and in using pressure recorders.

Subparagraph 5.1.2b

Comments. No comments received.

Discussion. The phrase "be able to withstand" was deleted and the phrase "have a working pressure equal to or greater than" was added. This revision was made for clarity.

Subparagraph 5.1.4

Discussion. The following revisions were made as a result of USGS review. The phrase "only at the boat landing" was added to the second sentence. The breakable synthetic tubing is intended for use only in emergencies. Valves or switches located elsewhere on the platform may be used for testing the Emergency Shutdown (ESD) system.

The following paragraph was added: "Electro-pneumatic systems shall meet the corresponding design and functional requirements as those which apply to pneumatic systems." No provisions were made in the original Order for electropneumatic shutdown systems.

Comments. Several commenters objected to the requirement for posting a schematic of the ESD system and to the requirement for platform shutdown not to exceed 45 seconds.

Other commenters suggested a time delay between closure of the surface safety valve (SSV) and the SSSV.

Discussion. The USGS accepted these suggestions. The posting of a schematic of the ESD system was considered unnecessary and the requirement was changed to require schematics to be maintained on the platform or nearest offshore field office. The paragraph was also revised to provide for a 2 minute planned time delay between closure of the surface and subsurface valves.

Subparagraph 5.1.5

Comments. Several commenters objected to the requirement for spark arrestors on other than diesel engines on the bases that natural gas engines do not emit particulate matter, arrestors would be harmful to the engines, and that arrestors are not available for many natural gas engines, including turbines.

Discussion. These arguments are cogent and the requirement for arrestors was limited to diesel engines.

Subparagraphs 5.1.7a(1)(2) and (3); 5.1.7b(1) and (2)

Comments. No comments received.

Discussion. It was determined that both interstage and suction scrubbers should be protected. The Order was revised.

Subparagraph 5.1.8

Comments. Several commenters objected to the requirements for fixed water-spray systems in the well bays and to the language that chemicals may be used in lieu of a water-spray system only.

Discussion. The subparagraph was revised to limit the requirement for fixed water-spray systems to the enclosed well-bay areas and to permit the use of chemicals in lieu of water-spray systems.

The last sentence of the second paragraph was revised by adding the following phrase: "unless an alternate firefighting system has been approved by the District Supervisor." This statement was added to be consistent with the third paragraph, which allows the use of a chemical system.

Comment. It was suggested that the proposed requirement for "at least 30 minutes of run time for fire pumps during platform shut-in" was inadequate and that the same should be increased to 12 hours.

Discussion. USGS disagrees. The present time requirement should provide enough time to control the fire or to take other actions.

Subparagraph 5.1.9a

Comments. Several commenters requested that the term "adequate ventilation" be defined.

Discussion. The definition of adequate ventilation, as defined in API RP 14C, was adopted.

Subparagraphs 5.1.9a (1), (2), and (3)

Comments. Several commenters found the definition of a high-hazard area vague and incomplete. One commenter also remarked that it is impractical to show the multiplicity of fusible plugs on a posted diagram.

Discussion. It is agreed that the definition of a high-hazard area, as presented, is inadequate and the posting of a schematic of detection points does not serve a useful purpose. The subparagraph was deleted.

Subparagraph 5.1.9b

Comments. Several commenters recommended to allow the low-level concentration gas detection devices to be automatic; whereas, the high-level concentration or hazardous gas detection devices would still be the manual-reset type.3Discussion. The main danger of explosion is in the high-level gas concentrations. It is in this area where a manual-reset alarm is important. On the other hand, in areas of low gas concentrations, it becomes burdensome to continuously have to manually reset alarms where an automatic device would suffice. The Order was revised.

Subparagraph 5.1.9c

Comments. Several commenters objected to the requirement for the use of both fuel gas odorant and an automatic gas-detection and alarm system.

Discussion. It was determined that in continuously manned areas of the platform, either an odorant or an automatic detection and alarm system would suffice.

Subparagraph 5.1.9d

Comments. One commenter recommended that this requirement should be deleted on the basis that it is ambiguous and subject to arbitrary interpretation and that the other subparagraphs provide adequate descriptions of gas detector and alarm requirements.

Discussion. This recommendation was not adopted. This subparagraph gives the District Supervisor the authority to make a decision in areas that are not readily discernible—grey areas. It is not an attempt to be arbitrary, but instead, to ensure safety.

Subparagraph 5.1.9e

Comments. One commenter suggested that fire and gas detection systems are not directly addressed by the 1978 National Electrical Code (NEC). Another commenter stated, "It may be preferable to refer to API RP 14F, First Edition, July 1978, * * *."

Discussion. The USGS agrees with these comments. Subparagraph 5.1.9e was rewritten to delete the reference to NEC, and to add the documents suggested by the commenters.

Subparagraphs 5.1.10

Comments. One commenter suggested that language be added granting authority to the Supervisor [DCM, Offshore Field Operations] to grant departures for the use of nonshielded secondary leads on certain 2-cycle engines.

Discussion. The DCM, Offshore Field Operations, has the authority without so stating in this subparagraph. The subparagraph was not revised.

Subparagraph 5.1.10d

Comments. Two commenters remarked that posting of an elementary schmatic would serve no useful purpose and the requirement should be deleted.

Discussion. Ths posting of a schematic does not serve a worthwhile purpose. However, the schematic should be available for those in charge of maintaining the system in operational order. The subparagraph was revised.

Subparagraph 5.1.10e

Comments. One commenter requested that the term "qualified" be defined.

Discussion. Language was added to specify that qualified persons are those "personnel who are familiar with the construction and operation of the equipment and the hazards involved."

Subparagraph 5.2

Comments. No comments received.

Discussion. For clarity, language was added to subparagraph 5.2c that explicitly exempts atmospheric and pressure vessels, when taken out of service, from compliance with safety device requirements, provided the vessels are securely isolated from production facilities and with the intention that they remain isolated for an extended period.

Subparagraph 5.3

Comments. Several commenters requested that the requirement be qualified to cover only those operations which are significantly different from those in the General Plan. This is intended to avoid duplicate paperwork and submittals.

Discussion. This suggestion was adopted. If not reworded, it would impose an unnecessary paper burden on the operator if a supplemental plan should be required each time wireline, workover, or other activities were performed simultaneously with production operations.

Subparagraphs 5.4 and 5.4d

Comments. One commenter noted that subparagraph 5.4d "* * * rules out hot tapping as an accepted practice." The commenter also noted that "Eliminating

hot taps will result in significant production losses."

Discussion. It is agreed that hot tapping should not be "ruled out." It is recognized that welding, burning, and hot tapping operations should be provided for in subparagraph 5.4. Therefore, the phrase "and Burning" was added to the title of this subparagraph. Additionally, in order to clarify and emphasize the safety aspects and intent of subparagraph 5.4, it was reorganized to include the following subparagraphs:

5.4.1 *General Welding, Burning, and Hot Tapping Plan.*

5.4.2 *Designated Safe-Welding and Burning Areas.*

5.4.3 *Undesignated Welding and Burning Areas.*

New subparagraph 5.4 contains requirements "a" through "d," and includes a paragraph to define "welding" and "burning." The final paragraph in subparagraph 5.4 reads as follows: "All offshore welding and burning shall be minimized by onshore fabrication, when feasible." This is not a new requirement; it appeared as the last sentence of the third paragraph of former subparagraph 5.4. All of the remainder of the requirements under former subparagraph 5.4 are now contained in new subparagraphs 5.4.1, 5.4.2, and 5.4.3.

The following revisions were made:

In subparagraph 5.4.1 (formerly contained in the third paragraph under 5.4), the sentence, "The plan shall be filed within 90 days after the effective date of this Order * * *" was deleted, since the clause is not necessary for the Arctic Order because there are no existing platforms or operating drilling rigs. Therefore, compliance is required prior to conducting welding and burning operations.

Subparagraph 5.4.3 (formerly contained in the second item "b" in 5.4), the third sentence read, "The fire watch shall not be a member of the welding crew," was deleted. This sentence is considered redundant, since the preceding sentence requires that the fire watch "* * * shall have no other duties while actual welding or burning operations are in progress."

Comments. One commenter stated that when proper precautions are taken, welding can be safely performed on a platform without installing a "Safe-Welding Area."

Discussion. When a safe-welding area cannot be established under the National Fire Protection Association Bulletin No. 51B, the Order provides under subparagraph 5.4.3 for procedures which will ensure safe welding.

Subparagraph 5.4.3e (formerly 5.4e)

Comments. One commenter maintained that drilling, workover, or wireline operations could be carried on simultaneously with welding if proper safety practices are enforced.

Discussion. This compromise in levels of safety was not adopted.

Subparagraph 5.4.3f (formerly 5.4f)

Comments. One commenter maintained that well production and welding in the well-bay area can safely occur simultaneously if proper procedures are followed.

Discussion. This compromise in levels of safety was not adopted.

Subparagraph 5.5h

Comments. No comments received.

Discussion. The wording in this subparagraph was revised in order to clarify the intent.

Subparagraph 5.51

Comments. One commenter suggested that this subparagraph should be deleted, since it could cause extensive shut-ins and create some safety hazards.

Discussion. It is agreed that subparagraph 5.51 is too general; the subparagraph was rewritten as follows: "1. All TSH devices on fired components shall be tested at least once every 12 months."

It is considered essential that the ESD system be periodically tested; therefore, a new subparagraph 5.5m was added as follows: "m. The ESD system shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The test may be conducted by closing at least one SSV from each of the ESD stations."

Subparagraph 5.6

Comments. One commenter stated that the quality assurance program provides the only 5-year record retention requirement, and under the FIRS program, the USGS will receive inventory and failure reports on all safety devices; therefore, the lessee should not be required to maintain duplicate records for the many devices not subject to the quality assurance program for more than 1 year at the offshore field office.

Discussion. It is required that some safety devices be tested at least once a year and the results recorded. In order to verify compliance, it is necessary that records be kept for longer than 1 year.

The following sentence was added to this subparagraph: "If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office." This revision was made for the same reason as discussed in subparagraph 3.11.

The last sentence in this subparagraph was deleted; it is considered redundant, since this subject is covered in subparagraph 6.2.

Subparagraph 5.7

Comments. One commenter noted that the third paragraph in subparagraph 5.7 is deficient in that (1) It does not require that the manufacturer's representatives be at least qualified by the manufacturer to service, install, or repair the safety system or device, and (2) it does not require that the supervisory person qualified in accordance with API RP T–2, who is supervising the manufacturer's representative, be familiar with or knowledgeable of the manufacturer's specific safety system or device.

The commenter further noted that the above deficiencies may create a situation where neither the manufacturer's representative nor the supervisor [DCM, Offshore Field Operations] is familiar with the specific system or device to be installed, serviced, or repaired.

Discussion. This comment is valid. The revised paragraph requires the person servicing the equipment and the DCM, Offshore Field Operations be qualified. Furthermore, as a result of this comment, items "b" through "g" were added.

Paragraph 6

Comments. It was suggested that the FIRS program be voluntary and not be required by those who see no practical benefit from the program.

Discussion. The purpose of the safety device FIRS program is for the USGS to identify potential problem areas, rather than having to experience an expensive and dangerous series of replacements. Implementation of a program on a voluntary basis would not provide sufficient meaningful information with regard to the various operating conditions, uses, and corrective actions taken.

Comments. It was commented that the FIRS system is a valuable tool for use by offshore operations, but that the decision to use specific equipment should be left to the lessee, taking into account the lessee's specific operating conditions and economics.

Discussion. It is not the intent of the FIRS program to tell lessees which equipment to buy, but to report what failure trends are occurring on individual pieces of equipment covered by the program. It could serve as a tool for lessees to identify which pieces of equipment should perform best in different operating conditions.

Subparagraph 6.1.1

Comments. It was suggested that provisions for a name or signature of the person completing or approving the failure data report submitted to the USGS, be included in the FIRS program. The commenters believed this would provide the safety equipment manufacturers with a point of contact for determining actual failure cause, contributing circumstances, and assist them in identifying the most appropriate corrective action.

Discussion. The USGS concurs with this recommendation and expanded the paragraph to include a signature of the person initiating and/or approving the data submitted. This signature will provide the equipment manufacturer with a point of contact for obtaining additional information required in the performance of their failure analysis.

It was recognized that subparagraph 6c which was included in the Appendix of the EA (45 FR 83905) should be included in subparagraph 6.1.1a for editorial clarity. Therefore, the following sentence was added to subparagraph 6.1.1a, "The lessee shall submit the originals of the forms to the USGS and retain the two copies." Subparagraph 6c was deleted. This revision is consistent with the FIRS Instruction booklet.

Subparagraph 6.1.2

Comments. It was suggested that the pneumatic or hydraulic fast-bleed relay used as a 3-way or 4-way fast block-and-bleed device with SSV or SDV actuators, be included in the listing of the required inventory and failure reporting.

Discussion. These relays are under consideration. The USGS plans to implement the FIRS program as it now stands and, based on the data gathered, decide on whether these relays should be added in the next revision of the FIRS program.

Subparagraph 6.1.3.1

Comments. One commenter suggested that it be made clear that only active devices and not those which have not yet been placed in service, are to be included in the reports.

Discussion. The devices to be included in the required reports were qualified as the active devices in the revised subparagraphs.

Subparagraph 6.1.4.1

Comments. One commenter suggested that the time frame be extended to at least 60 days to allow proper handling of the failure reports and to combine the malfunction and failure reports required by SPPE–1 and 2, and API RP 14B.

Discussion. The time frame allowed by subparagraph 6.1.4.1 is between 30 and 60 days (depending on the time of failure). In most cases, this time will be sufficient. In the event it is not, the USGS has provided a procedure in which a failure report with incomplete data may be submitted to the USGS and updated at some later date (see page F–13, column 73 and page F–15 in the FIRS Instruction Booklet).

Subparagraph 6.1.4.2

Comments. One commenter remarked that 30 days is insufficient time to reply and requested a change to 60 days.

Discussion. The 30-day time period was increased to 6 weeks. This is considered a reasonable response time.

Subparagraph 6.1.4.3

Comments. Several commenters suggested that the USGS differentiate by definition between failure and malfunction. They felt this was needed because failure and malfunction are defined in applicable API documents. Their concern was that the only time a failure occurs is when a piece of equipment fails to perform its designed function.

Discussion. With regard to defining failure and malfunction, the USGS believes there is no need to differentiate between the two. However, the report the USGS develops will contain a "critical" failure mode (failure) and an "other" mode (malfunction). This will, in essence, differentiate between equipment that did not perform with regard to its designed function (critical mode). The following sentence was added to provide additional information: "Examples of device failures are included in the FIRS Instruction Booklet."

Subparagraph 6.2

Comments. No comments received.

Discussion. Subparagraph 6.2, *Records,* was added to this Order. The proposed Order did not specify how long or where FIRS data records should be maintained by the lessee.

Paragraph 7

Comment. No comment received.

Discussion. In accordance with the "Memorandum of Understanding Between the United States Geological Survey of the Department of the Interior and the United States Coast Guard of the Department of Transportation concerning Regulation of Activities and Facilities on the Outer Continental Shelf of the United States" which was signed on December 18, 1980, and published in the on January 8, 1981 (45 FR 2199), paragraph 7 of the proposed order published on June 13, 1979 (44 FR 34073) was deleted. The proposed Order which was presented in the appendix of the EA on December 19, 1980 (45 FR 83906) contained the following version of this paragraph: 7. *Crane Operations.* Cranes shall be operated and maintained in accordance with U.S. Coast Guard regulations.

Since the U.S. Coast Guard has not published their new regulations governing crane operations, paragraph 7 has been revised as indicated below. This requirement will be revised to reference the final U.S. Coast Guard regulations when they are published.

7. *Crane Operations.* Cranes shall be operated and maintained to ensure the safety of facility operations in accordance with the provisions of "API Recommended Practice for Operation and Maintenance of Offshore Cranes," API RP 2D, October 1972, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation has approved for use. Records of inspection, testing, maintenance, and crane operators qualified in accordance with the provisions of API RP 2D shall be kept in the field area for a period of 2 years.

"API Specification of Offshore Cranes," API Specification 2C, February 1972, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation has approved for use shall be used as a guidelines for the selection of cranes.

OCS Order No. 7

Subparagraphs 1.1.1, 1.1.4, and 1.2.1

Comments. Two commenters believed that the disposal of muds, cuttings, or produced water into the ocean should be prohibited, especially in the Arctic areas. The concern was how this disposal affected the quality of the water and the organisms depending upon it.

Discussion. This suggestion was not adopted. USGS believes that these products can be disposed of properly through stringent Environmental Protection Agency disposal standards. Proposed lease stipulations prohibit disposal in water depths less than 10 meters due to inadequate circulation. In deeper waters, each lease is considered separately, and disposal practices are closely monitored to insure that sensitive areas will not be damaged. It should be noted that the words "Artificial Islands" were added to the title of subparagraph 1.1.4 in response to comments received on the EA. Refer to Section II of this Notice.

Subparagraph 1.1.3

Comments. Several commenters objected to the requirement for a closed sump on platforms and structures, since modern technology has produced many types of open-ended sumps that will adequately prevent the discharge of oil.

Discussion. The USGS agrees that properly designed open sumps will prevent oil discharge and has changed the subparagraph to allow for the use of all properly designed and maintained sumps. This subparagraph was revised further in response to comments received on the EA. Refer to Section II of this Notice.

Comments. One commenter recommended that the offshore disposal of contaminants from sumps should be prohibited.

Discussion. The Order prohibits disposal of any substance that will cause pollution. Contaminants from sumps will be treated as provided in lease stipulations and the authority of the District Supervisor.

Subparagraph 1.1.4

Comment. One commenter questioned why offshore islands (natural and artificial) were omitted from the heading, "Discharge from Fixed Platforms, Structures, and Mobile Drilling Units." This resulted in inconsistency with the heading in Section 1.1.3.

Discussion. The title of this subparagraph was revised to read, "Discharges from Fixed Platforms, Structures, Artificial Islands, and Mobile Drilling Units."

Subparagraph 1.2.3

Comments. Several commenters thought that reporting requirements of equipment disposed into the ocean should be limited to those that may pose a hazard to navigation and fishing.

Discussion. The limitations for the reporting of submerged objects are contained in the revision of paragraph 4 of OCS Order No. 1. The word "any" and the phrase "District Supervisor and to the" were deleted from subparagraph 1.2.3 of Order No. 7 for consistency with the revision of paragraph 4 of OCS Order No. 1.

Subparagraph 2.2.1

Comments. One commenter thought that a daily inspection of lease areas was not adequate for pollution detection. The suggestion was to provide for a systematic continuous monitoring system to detect spills and discharges.

Discussion. This suggestion was not adopted. The USGS believes that daily inspection procedures are adequate, especially when employing air surveillance. Special sensors that shutdown production operations in the event of malfunction are required in accordance with Order No. 5. No effective equipmen tthat is economically feasible has been developed for monitoring pollution around platforms.

Subparagraph 2.2.2

Comments. Several commenters objected to the daily inspection requirement for unattended platforms. It was suggested that these facilities should be inspected weekly and that the subparagraph should provide an exception in the event of prohibitive weather.

Discussion. The USGS does not agree with the suggestion of weekly inspections. Early detection of a leak or equipment malfunction is the key to pollution prevention. The phrase "or at intervals prescribed by the District Supervisor" provides latitude to waive the daily inspection requirement for those unmanned facilities which have a consistent record of pollution-free operation. In order to provide relief in the event of adverse weather conditions, the following sentence was added: "Daily inspections may be postponed in the event of adverse weather conditions."

Subparagraph 3.1

Comments. Several commenters were concerned with the adequacy of pollution-control equipment for arctic conditions.

Discussion. The USGS realizes the need for special pollution-control equipment in ice and snow areas and has revised this section to include appropriate equipment for the existing climatic conditions.

Comments. One commenter was uncertain whether this section allowed for the use of organized pollution-control companies.

Discussion. The intent of this subparagraph does allow for these companies, since the equipment "shall be available to each lessee * * * at a location approved by the Deputy Conservation Manager (DCM), Offshore Field Operations."

Subparagraph 3.2

Comments. No comments received.

Discussion. The first sentence was rewritten to permit the lessee to submit an Oil Spill Contingency Plan at an optional time.

Subparagraph 4.1

Comments. One commenter suggested that the language should provide for drills to be conducted by pollution-control equipment contractors. This procedure would avoid unnecessary repetitive training for each rig and would combine efforts in a more economical manner.

Discussion. The USGS agrees with this rational and adopted language that allows the contractor to conduct drills. The lessee retains responsibility for the drills.

The subparagraph did not specify any requirement for the frequency of the drills; therefore, language was added to require drills to be conducted at least once every 12 months.

Comments. One commenter suggested that the time schedule of drills should be contingent upon weather and drilling activities.

Discussion. Application may be made for time flexibility due to unforeseen events in the schedule submitted to the DCM, Offshore Field Operations.

Paragraph 5

Comments. It was questioned whether the USGS has the authority to approve the use of chemical agents or other activities, instead of the U.S. Coast Guard.

Discussion. The USGS has authority under the Memorandum of Understanding between the USGS and the U.S. Coast Guard, dated August 16, 1971.

OCS Order No. 8

Title and Preamble

Comments. No comments received.

Discussion. The title of Outer Continental Shelf (OCS) Order No. 8 was revised by deleting the words "and Associated Equipment" to be consistent with the content of the Order. Provisions for associated production equipment and operations are now contained in OCS Order No. 5.

General Comments

Comments. Two commenters contended that the Department of the Interior or USGS had not complied with the provisions of Executive Order (E.O.) 12044 concerning the analysis of the potential economic impact of the Platform Verification Program.

Discussion. E.O. 12044 was effective on March 23, 1978, and was not retroactively applicable to rules under revision at that time. OCS Order No. 8 was published for revision on August 25, 1977 (42 FR 42912), and on June 17, 1977 (42 FR 30917), the USGS published notice of intent to develop Platform Structural Verification Standards. When this proposed Standard was published for comment on December 5, 1978 (43 FR 56945), the Department of the Interior

determined that a regulatory analysis under E.O. 12044 was not required.

Comments. Four commenters objected to being asked to comment on OCS Order No. 8 without copies of three companion documents referenced in the Order, and one stated that without the complete package "the impact of the program is impractical to quantify."

Discussion. The USGS considers that the public was afforded appropriate opportunity to review and comment on all aspects of the Platform Verification Program and on OCS Order No. 8. The three companion documents were published for comment on December 5, 1978 (43 FR 56945), and the period for submittal of comments was extended to March 1, 1979. The various comments received were evaluated, and the first edition of these documents was printed at that time. There was little change in the basic content of these documents, except that the materials-requirements section was changed as a result of detailed input from industry technical representatives.

Comments. Three commenters expressed strong opposition to the Platform Verification Program and revised OCS Order No. 8 because it "will certainly result in increasing the cost * * * due to over-restrictive requirements," "* * * stifling industry growth," "* * * collectively, these items start to become quite burdensome," "* * * an unnecessary duplication of effort and expense and an unnecessary cost burden * * *."

Discussion. Numerous industry representatives stated that third-parties are commonly hired for design review, fabrication inspection, and installation monitoring. In addition, a National Research Council Marine Board panel, staffed by a broad cross section of experienced industry, government, and academic representatives, concluded that "the proposed third-party verification program for new offshore platforms will enhance the orderly extension of OCS oil and gas activities in an expeditious and efficient way by assuring the public and the Congress of the integrity of the fixed offshore platforms. A secondary benefit will be a more uniform application of current technology." The USGS believes that the revised Order and the Verification Program are vital, as our Nation's energy needs require extending the search for oil and gas into frontier OCS areas.

Comments. One commenter suggested a time limit of "10 days to two weeks" be placed on the Supervisor [DCM, Offshore Field Operations] to approve or disapprove plans.

Discussion. This may not be practical in all cases, but when possible, the expeditious handling of all applications, reports, and verification plans will continue to be the USGS policy. Legislative constraints and regulatory directives influence such matters and must be followed.

Comments. Two commenters emphasized the importance of minimizing delay and strongly urged that fabrication be allowed to commence prior to final design approval.

Discussion. The USGA agrees, and appropriate changes were made in the revised Order.

Comments. One commenter stated that "* * * operators should be permitted to make repairs on a structure without approval being required * * *."

Discussion. The Order requires approval be obtained for *major* modifications and repairs. Furthermore, if certain damage requires immediate repair to assure structural integrity, the Order will in no way jeopardize such a situation while the DCM, Offshore Field Operations, approval is pending. Prudent action should be taken under emergency conditions.

Comments. One commenter suggested that on the effective date of the Order the USGS should specify what structures are to be included or excluded from the new requirements.

Discussion. The provisions of this Order are not retroactive. It applies to all new platform applications and major modifications or repairs received in the office of the DCM, Offshore Field Operations, on or after the effective date of the Order. If the Plan of Development and Production was received, subject to submittal of platform design details, the revised Order does not apply.

Subparagraph 1.1

Comments. One commenter considered subparagraph 1.1 to be a major change in scope of the Verification Program; that the Requirements should be restricted to verification only and not to design, fabrication, and installation; and that the Gulf of Mexico is a mature region with no need for these requirements.

Discussion. The USGS does not agree with these comments. The primary thrust of the Platform Verification Program was for platforms to be installed in frontier areas and in deepwater locations, and for platforms of unique design. This remains a basic program concept to be accomplished by the two major elements: substantive (Requirements document) and procedural (OCS Order No. 8). These procedural requirements have been and are now contained in OCS Order No. 8. There is no major change in scope, nor can these requirements be limited to the verification function. The performance standards must be applied to the design, fabrication, and installation activities if the verification process is to be expedited. The proposed Order recognizes the maturity and successful past history of platform operations in the Gulf of Mexico Region. Subparagraph 1.3 requires the application of the Verification Program to only certain platforms that meet specified conditions intended to consistently apply the primary thrust of the program to the Gulf of Mexico.

Comments. It was pointed out that the words "the design fabrication and installation" should be deleted from the second and third lines of subparagraph 1.1.

Discussion. The correction was made to clarify the intent of the subparagraph.

Comments. One commenter recommended that single-pile caissons be removed from the "other structure" category.

Discussion. This recommendation was not adopted because a primary USGS responsibility for platform or other structure approval is consideration of and protection of the environment. Therefore, no exceptions can be permitted, particularly to exploratory well structures.

Subparagraph 1.2

Comments. A number of commenters objected to the inclusion of "repairs of damage" under the approval provisions of the Order in subparagraph 1.2. There is concern that delays in obtaining approval may pose risks and unsafe conditions to equipment, personnel, and the environment.

Discussion. It appears that the significant concern expressed by various commenters was possibly a misunderstanding of the intent of the subparagraph. It was intended to cover *major* repairs of damage to structural members affecting the structural integrity of the platform or other structure. In addition, the last sentence of subparagraph 1.2 was intended to provide for those situations where there was some question as to how to proceed, where a verbal approval may be appropriate for emergency repairs in a timely manner, or whether the condition is or is not determined to be a *major* modification or repair. Minor repairs, such as replacing damaged decking, handrails, stairways, or boat landings, are not intended to be subject to approval by the DCM, Offshore Field Operations.

Subparagraph 1.2 was modified to clarify the intent, adopting some of the suggested changes, but retaining the requirement for approval by the DCM, Offshore Field Operations, of major modifications and repairs. In addition, the subparagraph provides for the possibility of emergency repairs proceeding expeditiously with subsequent notification to and approval by the DCM, Offshore Field Operations.

Subparagraph 1.3

Comments. Two commenters suggested the deletion of the words "or repairs of damage" from subparagraph 1.3 to remove such operations from the requirements of the Verification Program.

Discussion. We agree with the suggestion and believe that appropriate review can be accomplished under subparagraph 1.2 prior to approval by the DCM, Offshore Field Operations, of major repairs of damage. The subparagraph was modified.

Comments. Three commenters expressed concern, confusion, or disagreement with the term "frontier area," especially in the Gulf of Mexico, as used in subparagraph 1.3.

Discussion. A "frontier area" on the OCS is one in which there have been little, if any, oil and gas exploratory and development operations, e.g., the entire Atlantic OCS Region, the Beaufort Sea, and all deepwater areas. For the Gulf of Mexico, the Mississippi, Alabama, Florida areas, and South Texas areas, all areas involving 400 feet or greater water depths, are considered frontier areas, as well.

Subparagraphs 1.4.1, 1.4.2, 1.4.3, and 1.4.4

Comments. One commenter stated that: "The documents listed in subparagraphs 1.4.1, 1.4.2, 1.4.3, and 1.4.4 are show as First Edition. These first editions should include any changes that are accepted from the comments made by interested parties on the draft documents," and another asked if the documents have been modified to include industry comments.

Discussion. We agree. All comments on these referenced documents were analyzed, and the documents were changed as required.

Subparagraph 2.1

Comments. Four commenters expressed disagreement with the words "prior to commencing any such work," due to the possible delays involved and apparently are willing to assume the risk that proposed changes will be approved. They suggested deletion of these words from subparagraph 2.1.

Discussion. The USGS is willing to accept this suggestion in order to minimize delays in the fabrication or installation process; however, the following sentence was added: "The lessee assumes the risk of making changes or modifications without prior approval of the DCM, Offshore Field Operations."

Subparagraph 2.2

Comments. One commenter questioned the certification requirement by a registered professional structural engineer or civil engineer specializing in structural design and suggested that "a certified or recognized naval architect-marine engineering firm would be able to qualify."

Discussion. The USGS insists upon certification by qualified professional personnel experienced in the structural design of offshore platforms and other structures covered by this Order. Any naval architect-marine engineering firm having such qualified personnel and experience will be acceptable, but all architect-marine engineering firms, certified or recognized, do not meet this requirement. Therefore, no change has been made to paragraph 2.

Subparagraphs 2.3, 2.4 (2.5), and 3.1

Comment. Two commenters suggested removing the words "or repairs" from subparagraphs 2.3, 2.5, and 3.1.

Discussion. We agree with the suggestion, and the subparagraphs were modified. In addition, the title of subparagraph 2.5 was changed from "Commencement" to "Approval" to better identify the intent of the subparagraph. Also, for editorial clarity, the order of subparagraphs 2.4 and 2.5 was reversed and subparagraph 2.4 became 2.5 and subparagraph 2.5 became 2.4.

Subparagraph 2.4 (2.5)

Comments. Numerous commenters expressed concern about the possible delays that may result from the provision in subparagraph 2.5, which requires design approval "prior to commencing the fabrication."

Discussion. We agree, and the words "prior to commencing the fabrication and obtain approval for the" were deleted. The wording was revised to read ". . . obtain approval for the design and fabrication from the DCM, Offshore Field Operations, prior to. . . ."

Subparagraph 3.2

Comments. One commenter questioned the required design documentation for approval of "major platforms" as compared to "single-pile caissons and other small well protectors."

Discussion. We agree that less design documentation will be necessary for a single-pile caisson than for a major platform; however, the exact details will be determined on a case-by-case basis with the concurrence of the DCM, Offshore Field Operations.

Subparagraph 3.2.1

Comment. One commenter recommended replacing the word "approval" with the word "submittal" in subparagraph 3.2.1 in order to expedite the overall verification process.

Discussion. We agree with the recommendation and subparagraph 3.2.1 was modified.

Comments. Four commenters pointed out that "finalized construction drawings" may not be available to be included with the submittal of design documentation.

Discussion. Subparagraph 3.2.1 was revised to require submittal of design drawings and material specifications for primary load-bearing structural members. The submittal of construction drawings and specifications will be required as a part of the Fabrication Verification Plan (Subparagraph 3.3), and finalized as-built drawings are to be retained and made available by the lessee for the functional life of the platform or other structure (paragraph 4, *Records*).

Comments. One commenter suggested that material specifications need not be submitted if the platform is designed in accordance with the requirements.

Discussion. We disagree with this suggestion. The characteristics of the materials of construction are a very pertinent design consideration, and their documentation is necessary for a meaningful design review.

Comments. One commenter inquired as to what information is contained in the Plan of Development and Production and if platform design data is included in the Plan.

Discussion. The complete details on submittal of Plans of Development/Production are contained in 30 CFR 250.34 of the OCS Operating Regulations. Platform design documentation is a necessary part of the Plan. This documentation must at least present a preliminary design sufficient to assess the approach proposed and its applicability.

Subparagraph 3.2.1.1

Comments. One commenter strongly questioned "the need for and the advisability of adding" the Universal Transverse Mercator grid system coordinates for platform location data in

subpargraph 3.2.1.1 as "an unjustified increase in paperwork and * * * source of confusion."

Discussion. Concern seems to be unfounded as conversion tables and techniques are readily available, and these are generally accepted methods of accurately describing a location. The USGS receives public requests for coordinates of a platform location on each of the systems.

Subparagraphs 3.2.1.1c and 3.2.1.1d

Comments. Two commenters pointed out that complete details may not be available to comply with the requirements of subparagraphs 3.2.1.1c and 3.2.1.1d at the time design documentation is submitted.

Discussion. The *General Platform Information* requirements need not all be submitted with the design documentation, and it will be permissible to supplement the application when these details are available.

Former Subparagraphs 3.2.1.1g and 3.2.1.1h

Comments. Two commenters suggested omitting items "g" and "h" in subparagraph 3.2.1.1 because "g" is redundant and "h" is unclear.

Discussion. We agree that item "g" is redundant, as Material Specifications are required by subparagraph 3.2.1.4c; therefore, it was deleted from subparagraph 3.2.1.1.

We do not think item "h" (Design Standard) is unclear; however, we feel that the objective is obtained by receipt of the documentation required by subparagraph 3.2.1 and the verification process. Therefore, item "h" was also deleted.

Subparagraph 3.2.1.2 and 3.2.1.3

Comments. One commenter suggested that the level of detail and the methodologies to be used regarding information required in the environmental reports which accompany the Plan of Development and Production be clarified and, further, that an explanation be provided as to the relationship of this information to the environmental information required under OCS Order No. 8.

Furthermore, the commenter recommended that the following requirements be included in the environmental information to be submitted in accordance with OCS Order No. 8:

1. Tests should be conducted to determine the concentration of light hydrocarbons in the seabed and subsurface soils and sediments.

2. Side-scan sonar profiles should be conducted over the sites proposed for structures to determine if geologic (e.g., sand waves) or manmade hazards are present.

Discussion. discussion of the details and methodologies to be used for information required by 30 CFR 250.34 is beyond the scope of OCS Order No. 8. However, 30 CFR 250.34 requires "a narrative description of the existing environment, with an emphasis on those environmental values that maybe affected by the proposed action"; whereas, the requirement for submittal of environmental information under OCS Order No. 8 is for determination of the effects of the environment on the structural integrity of platforms to be installed in OCS waters.

Concerning item 1, subparagraph 3.2.1.3a requires the type of data submittal which will indicate any existence of light hydrocarbons. Concerning item 2, whereas the use of side-scan sonar is not specifically called for, the identification of sea floor hazards is required by subparagraphs 3.2.1.3a, c, and e.

Comments. One commenter suggested that the phrase "* * * wind and gust velocities with relative heights * * *" be replaced with "* * * vertical distribution of wind and gust velocities * * *" in subparagraph 3.2.1.2a.

Discussion. We agree with this suggestion, and the wording was modified.

Comments. One commenter suggested that the word "data" used in subparagraphs 3.2.1.2a and 3.2.1.2c be replaced by the word "criteria."

Discussion. The USGS disagrees with this suggestion. The use of the word "data" in 3.2.1.2a is considered to be appropriate and corresponds to its use (with accompanying description) in subparagraph 2.1.2 of the Requirements. However, we do agree that the term "loading data"; used in subparagraph 3.2.1.2c should be replaced by the term "derived loads," and that wording was modified.

Comments. Two commenters suggested that subparagraph 3.2.1.2b be deleted in view of the fact that the subject matter is also contained in subparagraph 3.2.1.3.

Discussion. We agree with this suggestion, and the appropriate modification was made.

Comments. One commenter suggested that the USGS obtain geophysical and soil-boring information directly from the seismic and drilling contractors.

Discussion. We disagree with this suggestion. The USGS requires the submittal of such information from the lessees.

Subparagraph 3.2.1.3b

Comments. One commenter suggested that subparagraph 3.2.1.3b should be stated in more general terms by ending the sentence after the word "foundation."

Discussion. We agree with this suggestion, and the appropriate modification was made.

Subparagraph 3.2.1.3c

Comments. One commenter suggested that a soil stability analysis will not be necessary in areas where repeated analysis and soil-boring data indicate stable bottom conditions.

Discussion. We agree that the present wording should be clarified to reflect this fact, and subparagraph 3.2.1.3c was modified.

Subparagraph 3.2.1.4d

Comments. Two commenters suggested that subparagraph 3.2.1.4d is unclear and should be clarified or deleted.

Discussion. We agree, and the subparagraph was modified.

Subparagraphs 3.2.1.4e and 3.2.2b

Comments. One commenter suggested that the discussion regarding structural fatigue be relocated from subparagraph 3.2.2b to 3.2.1.4e.

Discussion. We agree with this suggestion, and the discussion on fatigue was moved to subparagraph 3.2.1.4e.

Comments. Two commenters questioned the necessity of performing a fatigue analysis of platforms for which the use of high-strength steel is limited to only a small percentage of the total structural members.

Discussion. In general, if primary load-bearing structural members are fabricated of high-strength steel for the purpose of using higher allowable cyclic stress level (higher than those allowed for mild steel), a fatigue analysis will be required for those members.

Subparagraph 3.2.2

Comments. One commenter recommended replacing the word "approval" with the word "submittal" in subparagraph 3.2.2 in order to expedite the overal verification process.

Discussion. We agree with this suggestion, and the subparagraph was modified.

Comments. One commenter suggested removal of the words "or repairs" from subparagraph 3.2.2 in order to remove such operations from the requirements of the Verification Program.

Discussion. We agree with the suggestion, and the subparagraph was modified.

Comments. One commenter suggested deletion of the words "as a part of the plan" in subparagraph 3.2.2.

Discussion. We disagree with this suggestion as this information should be available at the time of submission of the Design Verfication Plan. It is believed that partial submissions of this type could lead to confusion, unnecessary disputes, and unnecessary delays.

Comments. One commenter suggested that whenever the word "plan" is used in subparagraph 3.2.2., an identification be made as to which "plan" is being referred.

Discussion. We agree with this suggestion, and the appropriate identification was added.

Comments. One commenter questioned the uniformity of the level of involvement of the CVA's [certified verification agent] in various projects.

Discussion. The USGS will ensure that a minimum required level of involvement be maintained by the certified verification agent (CVA).

Comments. One commenter suggested that it will be a duplication of effort for the lessee to furnish the qualifications of the CVA, as this information will be obtained and maintained by the Platform Verification Section.

Discussion. A CVA's qualifications may be initially submitted to the USGS, either by CVA directly or through the lessee. The requirement for submission of qualifications addressed by this comment is to ensure that the appropriate personnel on the staff of the CVA will be used and that the qualifications of the CVA have not changed.

Comments. One commenter suggested that the USGS should not require resubmittal of the Verification Plan(s) in the event the CVA changes.

Discussion. The USGS does not agree with this suggestion. We believe that if such drastic situation should occur, i.e. a CVA change, a change in the way that verification will be carried out will also occur.

Subparagraph 3.3

Comments. One commenter suggested the deletion of the words "or repairs" from subparagraph 3.3 to remove such operations from the requirements of the Verification Program.

Discussion. We agree with the suggestion, and the subparagraph was modified.

Comments. Numerous commenters expressed concern about the possible delays that may result from the provision in subparagraph 3.3 requiring the lessee to submit a Fabrication Verfication Plan subsequent to approval of the design.

Discussion. We agree, and the word "approval" was deleted and the word "submittal" inserted in subparagraph 3.3.

Comments. One commenter suggested that we should specify what information is required when submitting the Fabrication Plan.

Discussion. We agree with this suggestion, and subparagraph 3.3 was modified to incorporate the following: "* * * fabrication drawings and materials specifications of all the primary load-bearing members included in the space-frame analysis * * *."

Subparagraph 3.4

Comments. One commenter suggested the deletion of the words "or repairs" from subparagraph 3.4, to remove such operations from the requirements of the Verification Program.

Discussion. We agree with the suggestion, and the subparagraph was modified.

Comments. One commenter suggested the deletion of the words "subsequent to the approval of the fabrication" from subparagraph 3.4.

Discussion. We agree with this suggestion, and the subparagraph was modified to require submittal of the Installation Verification Plan subsequent to the submittal of the Fabrication Verification Plan.

Paragraph 4

Comments. One commenter suggested "* * * it may be desirable to maintain design records for the life of the platform, maintenance of all other records should be limited to 5 years."

Discussion. We do not agree with this suggestion because this type of information is useful and necessary for consideration during future modifications and repairs during the useful life of the structure, which is normally 20 years or more. However, the subparagraph was modified to incorporate the following: "the as-built structural drawings, the design assumptions and analysis, and a summary of the NDE [Nondestructive Examinations] records."

OCS Order No. 12

Paragraph 1

Comments. One commenter believed that the new requirement to identify all public information is confusing and not consistent with the current practice of only identifying confidential information. It was suggested that the current system be retained.

Discussion. This suggestion was not adopted. In order to maintain confidentiality of certain information, this new system will insure that only those items marked "Public Information" will be made available. All other information will be held confidential.

Paragraph 2

Comments. One commenter questioned the words, "It has been determined" and asked on what basis the USGS made such a determination. There was concern as to the operator's competitiveness after release of certain information.

Discussion. The basis for such a determination that certain data shall be made available is in accordance with the Freedom of Information Act, the OCSLA, and the Department of the Interior regulations contained in 30 CFR Part 250. Definitions of confidential and public information are found in 30 CFR 250.2, "Definitions," and 250.3, "Data and information to be made available to the public."

The USGS believes that the term, "It has been determined" is vague and subject to interpretation, and in order to avoid confusion, the words were deleted from the introductory sentence of paragraph 2 and subparagraph 2.10.

Subparagraph 2.1

Comments. No comments received.

Discussion. Nonproprietary well status information must be reported in accordance with 30 CFR 250.93, *Monthly report of operations.* The remarks column is often used to make proprietary explanatory statements. The subparagraph was revised to require the lessee to delete such proprietary information from the public information copy.

Subparagraphs 2.2.2 and 2.2.3

Comments. It was suggested that "Item 26, Type Electric and Other Logs Run" should be exempt from public inspection after commencement of production, since certain geological and geophysical data are exempt from disclosure under the Freedom of Information Act.

Discussion. This suggestion was not adopted. It is the policy of the Department of the Interior to make records available to the greatest extent possible according to 43 CFR 2.13(d), which implements the Freedom of Information Act, and in accordance with 30 CFR 250.2 and .3 which implement the OCSLA.

In addition, lease stipulations require that certain geological and geophysical information are subject to public inspection according to 30 CFR 250.3,

"Data and information to be made available to the public."

Comments. One commenter was concerned that the release of shallow seismic data for public inspection would destroy the operator's competitiveness since this information can have significance for geology at greater depths.

Discussion. The USGS beleives that shallow seismic data will not harm the operator's competitiveness, since the information is extremely theoretical and, without deeper seismic work, is virtually useless for deep stratigraphic interpretation. In the event of reasonable claim of certain confidential information, the DCM, Offshore Field Operations, may grant exemptions from public scrutiny, as stated in this subparagraph.

Subparagraph 2.11

Comments. One commenter suggested that confidential and proprietary information should not be made available upon the expiration of the lease if "there is unleased federal or state owned acreage in the immediate vicinity of the expired lease." This could result in competitors' access to information acquired at lessee's expense.

Discussion. The request is contrary to the language of 30 CFR 250.3, "Data and information to be made available to the public." This regulation requires release of all information in a certain length of time or as long as the lease remains in effect, *whichever is less.* This means all information is available at least by the expiration of the lease. Subparagraph 2.11 reflects this thought.

Paragraph 3

Comments. No comments received.

Discussion. The introduction to paragraph 3 was revised to include the caveat "Except as provided in 30 CFR 250.3, 250.4, and 252.7, the release of this data is subject to the following restrictions." This caveat is necessary to reflect revisions in the 30 CFR 250 and 252 regulations which were published in the **Federal Register**, on August 7, 1979 (44 FR 46404) and on October 26, 1979 (44 FR 61886).

Subparagraph 3.2

Comments. No comments received.

Discussion. In order to be consistent with 30 CFR 250.3, "Data and information to be made available to the public," the USGS adopted the language of the regulation regarding geological and geophysical data in sections 3.2(a) and 3.2(b).

II. Summaries and Discussions of Comments Received in Response to Federal Register Notice (45 FR 83868) on the Environmental Assessment

General Comments

Comment. Some commenters believe the adoption of these Orders is a major Federal action requiring the preparation of an Environmental Impact Statement (EIS). They cite a passage from *Alaska v. Andrus* 580 F. 2d 465,478 (D.C. Cir. 1978), which suggests that the USGS must prepare an EIS.

Discussion. We have summarized the Orders, considered their effect, and considered the effect of alternative Orders. We followed the Court of Appeals' suggestion. See 580 F.2d 480. We find that the adoption of these Orders is not a major Federal action. We think the Court was correct to observe that:

> While the Orders may have considerable impact on environment, the impact can arise only after a lease sale has been held and drilling operations have commenced under the terms of the Orders. The promulgation of the Orders cannot, by itself, affect the environment in any way.

Before a lessee can drill a well, the lessee must first have a lease and an approved exploration plan. An EIS is always prepared before leasing, and an EA is always prepared before an exploration plan is approved. These documents will analyze the effects of oil and gas drilling. We can see little benefit in preparing an EIS that repeats the analysis of the EIS for the Beaufort Sea Sale BF.

Operating Orders are restrictions on lessees. Like lease stipulations, they are mitigating measures, helping to reduce the risk that oil and gas operations will harm the environment. They do not permit the lessee to drill; the lease and plan do that. The District of Columbia Court of Appeals recognizes that this is an important distinction.

"[Lease stipulations] constitute *restrictive* instructions to the lessee which can only inhibit the scope of the lessees' operations. As the stipulations are in no way *permissive* it is underly speculative how else the Secretary might have thought to discipline the lessee." *North Slope Borough v. Andrus,* slip. op. at 27.

The Court of Appeals concluded that the lease sale EIS did not have to present a "full-blown explication of alternative lease stipulations." Id. at 26. By analogous reasoning, we think that the issuance of the Arctic OCS Orders does not require an EIS.

Comment. A few commenters remarked that our 31-day period for comments on the assessment was too short.

Discussion. Everyone had earlier opportunities to comment upon the proposed Orders. As for commenting on the assessment, we are not required by the Council on Environmental Quality to circulate an EA for comment. We also note that when an agency initially decides not to prepare an EIS in a situation when it normally would, the Council requires only a 30-day period between the announcement of the decision and the final decision. See 40 CFR 1501.4(e)(2). If 30 days is reasonable there, we think it is reasonable here. We believe we allowed a fair amount of time for comments.

Comment. One commenter stated that the Orders should be expanded to all Arctic waters off the Alaska coast, including the Bering Sea.

Discussion. We have reviewed this comment carefully, and from an operational standpoint, we disagree. Climatic conditions in the Beaufort Sea and the Chukchi Sea may have many similarities with the Bering Sea, but environmentally, there are considerable differences that require different operational approaches. Different ice and permafrost conditions occur in each area. We believe a set of Orders that tried to encompass both areas would be difficult to write and organize, as well as cumbersome to use. We favor splitting the two areas—north of the Bering Straits to be known as the Arctic Area and south of the Bering Straits to be known as the Bering Sea Area.

Part I of EA

Comment. One respondent was not in agreement with the statement contained in Part I.A. that oil and gas exploration activities will not cause significant harm to the arctic environment if they are conducted properly. The commenter cited the potential for oilspills associated with ice override as a threat that compliance with the Arctic OCS Orders will not effectively mitigate.

Discussion. In response, the USGS reaffirms the belief that arctic OCS oil and gas activities can be conducted in a manner that will prevent significant impacts on the environment. With respect to the specific concerns expressed about ice override, these Orders provide that ice movements be continuously monitored. Ice override can be avoided by using special island design and construction techniques and by digging trenches around the island. Trenching is a routine measure taken around existing operations conducted from islands in the arctic.

Comment. Many commenters objected to our interpretation of the restriction on

drilling from manmade islands seaward of the barrier islands. See 45 FR 83870.

Discussion. The commenter's objections were well taken. The EA stated that *each* artificial island built in water depths deeper than 13 meters had to be left in place for two winters before drilling could begin. The position announced in the Notice of Sale was this: "Drilling from platforms or structures located beyond the barrier islands in water depths in excess of 13 meters will be prohibited *until such time as a test platform or structure of the same type to be drilled from has been in existence in the sale area at a depth in excess of 13 meters for a period of two winter seasons.* Certification of the test structure by an independent engineering firm will be required prior to approving drilling operations from the structure.

The Director will determine the adequacy of the test structure after consultation with designated representatives of the North Slope Borough and the Regional Technical Working Group of the National Outer Continental Shelf Advisory Board, prior to approving drilling operations from the test structure or from platforms or structures of the same type in water depths in excess of 13 meters."

The EA has been corrected to reflect these provisions.

Comment. Two respondents commented on the possibility that gravel islands might have to be removed at abandonment, as provided by Federal Lease Stipulation Nos. 1 and 3. One recommended that these structures be removed in every case to reduce the potential for chronic siltation, structure proliferation, and interference with circulation and to promote the reuse of gravel. The other commented that the net effect of removing an island would be to more than double the environmental impact.

Discussion. The provisions of the Federal lease stipulations were developed by representatives from various agencies in the Department, including the Bureau of Land Management (BLM), U.S. Fish and Wildlife Service, Heritage Conservation and Recreation Service, and USGS and representatives of the National Marine Fisheries Service of National Oceanographic and Atmospheric Administration (NOAA), Environmental Protection Agency and the State of Alaska. In developing these stipulations, due consideration was given to comments that were received on the proposed stipulations included in the Draft Environmental Impact Statement for the Beaufort Sea Lease Sale. The Federal lease stipulations currently in effect on active OCS leases will control.

Comment. A commenter recommended that the Department prepare its EIS on a development and production plan before the plan is filed. "[T]he EIS process [should be] carried out concurrently with delineation of the productive limits of the new field."

Discussion. Section 25(e)(1) of the OCSLA Amendments of 1978 requires the USGS to prepare the EIS on the plan itself. We will work to reduce delay when assessing these plans.

Comment. Several respondents made comments similar to the following comments on the EA:

"The statement that artificial methods of oil and gas recovery will be employed after perhaps 10 to 20 years when the natural reservoir pressure has dropped significantly is not in keeping with state-of-the-art petroleum engineering practice. Under normal operating conditions, reservoir pressure would not be allowed to decline significantly over a period of 10 to 20 years before initiating some form of pressure maintenance program. Artificial lift methods may be required in some wells early in the producing life of the field. These will vary according to the depth, pressure, and type of fluids being produced. Pressure maintenance programs are also initiated relatively early to prevent the reservoir pressure from dropping significantly. Depending upon the type, enhanced recovery methods could be applied at any time during the life of the reservoir. In addition, the EA implies that water flooding or artificial lift operations are 'enhanced recovery' methods, which is inconsistent with the accepted usage of these terms."

Discussion. We agree. In response, the first sentence of the subject paragraph in the EA has been modified as follows: "When a field is developed, pressure maintenance programs are initiated relatively early to prevent reservoir pressure from dropping significantly. Enhanced recovery methods can be applied at any time during the life of the reservoir, subject to reservoir conditions encountered."

Comment. Several commenters addressed Part I.D. of the EA (Summary of Potential Environmental Effects of Exploration Activities in the Beaufort Sea). Comments on this part were both general and specific in nature and ranged from concerns that potential effects of exploration activities were understated and incomplete to concerns that the manner in which potential impacts were presented did not make it clear that a potential effect does not necessarily mean a probable effect.

Discussion. We respond to those comments collectively, as follows: It is noted in the first paragraph of Part I.D. of the EA that the discussion of potential effects of exploration activities represents a brief and general summary of the exploration related impacts detailed in the EIS prepared by the BLM for the Beaufort Sea Lease Sale. We believe that Part I.D. accurately summarizes the related information contained in the Beaufort Sea EIS, but we do acknowledge that it was subject to varied interpretation. It is noted in Part I.B. of the EA that a separate EA will be prepared by the USGS for each exploration plan prior to approving or disapproving the conduct of specific exploration activities. The exploration plan EA will describe the potential site-specific impacts of activities proposed. This will include any new or additional information gathered by the USGS not found in the Beaufort Sea EIS. We believe that a review of the plan-specific EA and Beaufort Sea EIS must be undertaken before an objective judgment can be made regarding the potential effects of a particular exploration proposal.

With respect to exploration well blowout potentials, several respondents commented that our use of USGS blowout statistics for the Gulf of Mexico is misleading. Some commenters felt that these statistics underestimate blowout potentials for the Arctic Area because the operating environment is unusually hostile, and others felt that blowout potentials would probably be reduced in the Arctic Area because gravel islands and land-type drilling rigs will be used instead of classical offshore drilling equipment. We cautioned in the EA that forecasting arctic blowout probabilities based on statistics from other areas could be misleading. These statistics were included for the purpose of providing a general frame of reference for those persons unfamiliar with the blowout experience in other OCS areas.

In response to comments received stating that the summary did not consider the environmental impact potentials of development activities, we reiterate a statement made in Part I.C. of the EA. At some point in the development phase of Beaufort Sea leases an EIS will be prepared for at least one development and production plan to examine the effects of development activities on the environment.

Finally, one respondent was concerned that the discussion in the EA does not consider the potential environmental effects of seismic exploration conducted in the lease sale area. The activities referred to in this comment may include both prelease and

postlease geological and geophysical activities. The postlease activities provide information necessary for developing an exploration plan. They were not considered in the EA, because they do not constitute activities that are conducted under an approved exploration plan. However, an analysis of environmental effects of these activities will be conducted by the USGS. Proposals to conduct prelease and certain other types of geological and geophysical survey activities are evaluated in accordance with the provisions of the Department's regulations found in 30 CFR 251. In addition, for Beaufort Sea OCS leases, lessees will be required to notify the USGS of their intentions to conduct postlease "preliminary activities" (30 CFR 250.34–1) as provided by the notice to Beaufort Sea bidders published at 44 FR 70238 on December 6, 1979. An analysis of the effects of these activities will be conducted prior to commencement of preliminary activities in order to identify potentially significant adverse impacts on the natural resources of the arctic OCS.

Environmental Effects of the Proposed Arctic OCS Orders and Alternatives

Comment. One respondent commented that the discussion of the proposed operating orders was inadequate. "The scope of the analysis of alternatives in the environmental analysis is too narrow. As a general matter, we believe that the analysis of alternatives must include operating restrictions imposed in areas as comparable as possible to the Arctic Sea, particularly in other areas with severe weather conditions. However, the Environmental Analysis bases its consideration of alternatives only on the operating orders adopted for the Gulf of Mexico. The Gulf is obviously not even remotely comparable to the Arctic Sea. We urge that the Department consider the restrictions adopted for the following areas in analysis of alternatives. First, it should consider the types of operating restrictions which foreign nations have imposed upon OCS operations in other extremely hazardous areas, such as the Canadian Beaufort Sea and the North Sea. Those areas also face extreme climatic problems. While they may not include ice and permafrost, the harsh conditions demand that exceptional precautions be taken to prevent accidents. Moreover, several accidents, including a major blowout, have occurred in recent years at offshore operations in the North Sea. Studies of the causes of those accidents and of the action necessary to stop blowouts and remedy their adverse consequences may have resulted both in significant changes in operating procedures and in requirements which are applicable to Arctic operation as well.

In addition, the Environmental Analysis does not adequately analyze the possibly harmful environmental impacts of the requirements in these orders. For example, while there is a definite need for good lighting of work areas during drilling, as the Arctic Operating Orders require, strong lights in an otherwise dark environment could attract birds and other species and wildlife. These wildlife could be killed or seriously harmed through collision with the drilling rigs or other structures. Therefore, it is important to assess the effects of having strongly lighted spots in the winter darkness.

The proposed Orders introduce some specific requirements as to the quality and quantity of equipment and materials which must be used and kept in storage during various operations. The Orders also require the lessee to perform various activities such as monitoring, surveillance, inspection, testing and reporting. While a prudent lessee might have implemented many of these requirements, some others, particularly those regarding equipment, materials and testing activities, would presumably not have been implemented voluntarily by the lessee. Consequently, these requirements will result in additional needs for manpower, logistics and space and such additional needs will aslo have environmental effects. Since these effects have not been addressed in the analysis, we recommend that a detailed consideration of these matters be made."

Discussion. USGS does not agree with this statement. In developing the Arctic Orders we searched for areas where comparable operations were being carried on. We examined North Sea operations. The North Sea has harsh weather conditions but they are not similar to the Arctic. More importantly, the character of operations are different. In the Alaskan Beaufort Sea most operations will be conducted from gravel or ice islands. In the North Sea all exploratory drilling operations are conducted from mobile drilling units. Canadian operations were also examined but were found to be dissimilar in some respects. In the Mouth of the MacKenzie River Delta, gravel islands are being built and used, while in the Canadian Beaufort and in the vicinity of the High Arctic Islands, some operations are accomplished using mobile drilling units. The Prudhoe Bay Field in Alaska, adjoining the Beaufort Sea lease area, was the only area that had comparable weather and operating conditions and a sufficient operating history for the USGS to use as a base for comparison. This field operates under the State of Alaska regulations. These regulations have evolved from the rules and procedures that governed Federal leases for years. Many of the State's requirements and procedures were adopted from the USGS operating manual. We believe that we could best accomplish our purpose by using a set of sound operating orders and changing them to meet specific arctic weather and environmental conditions. Many of the requirements of our Orders are refinements of the Canadian requirements written for operations under arctic conditions. We believe the statements about lighted areas being hazardous to birds is unsound. The seasonal drilling restriction allows only winter oprations for at least the first two years. Birds do not inhabit the area of operations during the winter season. If, at the end of the two-year period, the USGS determines that year-round activities will have unacceptable adverse effects on birds, the seasonal drilling restriction can be extended or other mitigating measures can be adopted. Additional personnel will not be required to implement Order requirements such as monitoring, surveillance, testing, and reporting, since these activities are common everyday practices of competent operators in the petroleum industry. Our inspection system will ensure that these activities are safely carried out. Furthermore, the impacts of personnel required for specific exploration activities will be addressed in the EA for each exploration plan.

Comment. One respondent objected to the manner in which the USGS treated the environmental impacts of the proposed Orders. The commenter believes that the USGS must determine the effectiveness of the Order provisions in reducing the potential for harm to the arctic environment.

Discussion. The USGS believes that it is not possible to make a quantitative assessment of effectiveness of the Order provisions in reducing the potential for environmental impact. Oil and gas activities on the U.S. OCS have long been subject to the provisions of operating restrictions. We have no data that accurately demonstrate the adverse effects of operating without OCS Orders. A comparative study could be conducted in an OCS area, such as the arctic, by allowing activities in part of the area to be conducted without regard to OCS Orders. Over a period of time,

the differences in observed environmental effects might then provide an objective measure of the effectiveness of the Orders. This approach to determining incremental benefits of OCS Orders is not acceptable for obvious reasons.

We should have included a statement in the EA pointing out that a quantitative assessment of impacts is not possible for the Arctic OCS Orders. In response to the comment, such a statement was added to the introductory paragraphs of Part II of the EA which contain the analysis of the environmental effects of the proposed Orders.

Comment. Several commenters responded to the requirements for marking of equipment in paragraph 5 of Order No. 1, as presented in the EA.

Discussion. Refer to the discussion of paragraph 5 of OCS Order No. 1 in section I of this Notice.

Comment. One commenter on the EA recommended we modify the Orders as follows: "Require the lessee to send USGS a copy of its notification to the Coast Guard of the location of each marine structure before the structure is emplaced."

Discussion. We believe it is unnecessary to adopt this recommendation. The USGS sends a copy of each exploration plan to the U.S. Coast Guard for review. The plan identifies the proposed location of each structure to be placed on the OCS. In reviewing the plan the U.S. Coast Guard will be made aware of the lessee's proposal to emplace a structure on the lease. Lessees should be aware of their obligations to notify each of the various involved Federal agencies concerning their operations.

Comment. One commenter believes that it is improper for the EA not to analyze Orders 6, 9, 11, 13, and 14. "The fact that Arctic Operating Orders for these activities have not yet been prepared makes it impossible to do a complete assessment of the environmental effects of the future oil and gas activities associated with the Arctic OCS Orders."

Discussion. These five Orders are currently being developed. We realize that the assessment does not have the scope that this commenter wishes, but we have assessed the currently proposed Orders thoroughly. The reasons for not proposing Orders Nos. 6, 9, 11, 13, and 14 were briefly identified in the introductory paragraphs of Part III.B of the EA. The Lease Sale EIS and the future EIS on a development and production plan will present a full review of these activities.

Comment. It was commented that the EA occasionally refers to the requirement that lessees show in their emergency plans that they will be prepared to drill one or more relief wells, whereas, the requirement in OCS Order No. 2 calls for the plan to show that the lessee will be prepared to drill a relief well.

Discussion. The intent here was to ensure that the lessees will do what is necessary to control a blowout, should one occur. In most cases when other efforts fail, this would entail the drilling of one relief well, which is the requirement of OCS Order No. 2, subparagraph 1.1a. If the first relief well is unsuccessful, a subsequent well(s) may need to be drilled, and the planning for drilling would be made at that time.

Comment. Some commenters felt that the EA did not cover the subject of blowouts in sufficient detail. In their view, the EA did not analyze sufficiently the importance of relief wells in controlling the amount of oil spilled from a probable blowout.

Discussion. The EA stresses the backup systems that prevent the occurrence of a blowout, the remote likelihood of an oil blowout in exploratory drilling, the success of other methods in controlling blowouts should one occur, and the use of relief wells only as a last resort. Further, the discussion highlighted that the time required to prepare a drilling pad for a relief well amounted to only a fraction of the total time required for the achievement of blowout control.

We believe that the subject has been amply discussed.

Comment. One commenter suggested that the OCS Orders should require the applicant to identify an alternate drilling platform which could be used to drill a relief well in the event of a loss of well control. It was stated, "This is desirable because it could significantly reduce the time to drill a relief well and the amount of oil spilled during a pollution incident. The applicant would not be expected to build redundant islands, etc., but would be expected to design his facilities such that a drilling pad could be rapidly constructed on the slope of the artificial island, or on bottom fast ice."

Discussion. Lessees' proposed plans with respect to relief wells will be examined to ensure that they are adequate from a timing and technical standpoint.

Comment. Another commenter stated that in order to assure that BAST is achieved, each general rig design should be subjected to a systematic risk analysis by identifying chains of failure that could lead to critical events, and that components which warrant redesign or redundancy can be identified and technology brought up to standard.

Discussion. Lessees are required to use the best available and safest technologies (BAST). As stated in the USGS document entitled, "The Use of Best available and Safest Technologies (BAST) During Oil And Gas Drilling And Producing Operations On The Outer Continental Shelf". "BAST is a broad concept, and like all broad concepts, requires careful consideration before specific applications. The modifiers 'best,' 'available,' and 'safest' are imprecise, especially when they are combined in the phrase 'best available and safest.' In addition, the other considerations specified in section 21(b) of OCS Lands Act amendments—'economically feasible,' 'significant effect,' and 'incremental costs v. incremental benefits'—further complicate interpretation of the requirement. The Marine Board Panel, in attempting to bring specificity to the meaning of these general terms, reviewed the legislative history and the experience the Environmental Protection Agency has had in interpreting technology mandates under the Federal Water Pollution Control Act, developed broad parameters for how these terms might be applied to OCS oil and gas operations." That discussion is abstracted in the following sections:

"Best"

There may be more than one "best" way to achieve a particular objective or do a particular job. It may be expected that "best" means that which would most completely fulfill the composite purpose of the legislation, not necessarily the most expensive or sophisticated.

"Available"

The House Committee was impressed with the technological advances made by the industry on its own and indicated its desire to have those advances (as actually used on at least some operation) applied universally. The Committee also wanted to encourage the development of new and improved technology to minimize risks to the environment. Discussion concerning the term "available control technology" found in the Federal Water Pollution Control Act Amendments of 1977 indicates that the technology does not have to be in actual use somewhere, but the technology must be available at a cost and at a time which the EPA Administrator determines to be reasonable.

The foregoing comments about the terms "best" also apply to the term

"safest". The legislative history of Federal Water Pollution Control Act Amendment of 1977 indicates that it means something more than "safe". The exact meaning would be left to administrative discretion.

"Technology" (and "Technologies")

In contrast, the meaning of "technology" (and "technologies") was extensively debated by the Congress. It was emphasized that more than one technology may be applicable as the best way to achieve a particular objective or to do a particular job. Hence, the word "technologies" was inserted. There was substantial concern about the anticompetitive and innovation-stifling impacts of designating single technology, technique, or product as "best" and banning the use of any other.

"Existing"

BAST is required for all new operations, but is required for existing operations only where practicable. It is clear that "existing" is at the time of the introduction of better or safer technologies and not at the time of the passage of the Act.

"Economically Feasible"

BAST is not required if not economically feasible. If the incremental benefits are clearly insufficient to justify the incremental cost it is not economically bearible. The choice of language was patterned after the terminology in existing environmental laws.

"Significant Effect on Safety, Health, or the Environment"

Congress provided little guidance as to when the incremental benefits are clearly insufficient to justify the incremental cost of utilizing BAST. The Secretary of the Interior urged that language be incorporated into the OCSLA Amendments of 1978 law that would prevent standards being imposed that were so costly as to prohibit the extraction of oil and gas. While not specifically adopting the approach recommended by the Secretary, the Conference Report states that "language provides for economic feasibility to be a balance of cost against benefits."

"Application of BAST"

Testimony and questioning at hearings which addressed the OCSLA Amendments of 1978 indicated that small, individual elements of an OCS operation were not the object of a BAST specification. BAST was not to be applied installation-by-installation, company-by-company, or lessee-by-lessee. Instead, the Department was to implement the requirement in a reasonable manner on an industrywide basis or with respect to classes or categories of operations. By requiring the use of BAST, Congress sought to assure the "highest degree" of safety in OCS operations, using an economic balancing process to prevent the possibility of unreasonable application. The OCS Lands Act Amendments clearly require that existing technologies be reviewed and the best available of those technologies be applied when practicable. The Amendments could also be interpreted to mean that new technologies should be developed if the existing technologies are proven to be inadequate. The BAST requirement is limited to technologies and is not designed to mitigate human errors.

The Marine Board findings lead to certain general principles:

- Technologies used during OCS drilling and producing activities should provide the safest and most reliable cost-effective operations.
- The BAST requirements should be applied in an efficient manner that recognizes the availability of the specific technology and the consequences of requiring or not requiring its use. The BAST program must encourage continuing improvement of the technological capability of the petroleum industry.
- Technologies in question are limited to equipment.
- When a gap in technology is discovered, the Government should take the lead in seeing that new technologies are developed.
- The BAST Program should provide for public participation in the development of requirements."

Comment. Some industry commenters are unhappy with 30 CFR 250.35. They want the 90-day rule increased to a 180-day rule in the arctic.

Discussion. A regulation, not the proposed Orders, governs this point.

Comment. One commenter recommended the following concerning the EA: "Monitoring of performance data should explicitly include monitoring of the rig for structural integrity by diver inspection, etc."

Discussion. We agree. Steps have been taken to develop a monitoring program for structural integrity. By notice on October 16, 1980 Federal Register (45 FR 68665), the USGS served notice of the intent to develop requirements for periodic inspection of fixed offshore oil and gas platforms for stuctural integrity.

Comment. On commenter stated, referring to the EA: "Evaluation of the operation of safety equipment in subfreezing conditions should explicitly include the effects of ice encrustations."

Discussion. We agree and believe the Arctic OCS Orders adequately cover this area. The Orders state repeatedly that all equipment used must function properly under subfreezing arctic conditions. The term subfreezing arctic conditions is an all-inclusive statement and covers ice encrustation.

Comment. Several commenters suggested that the requirement for the cement placed across permafrost zones to have a low heat of hydration so as not to thaw frozen formations be deleted. This recommendation is based on current experience which indicates that the heating effect of cements having high heats of hydration may not be be significant.

Another commenter recommended, "Instead of adopting an arbitrary standard such as 25 Btu/lb, it is recommended that some degree of certainty should be introduced by stating as acceptable cement (gypsum-base with heat of hydration of 15–18 Btu/lb) and allowing alternatives if they, too, have appropriate qualities. These might be (1) minimizing permafrost melt, (2) good set-up and strength characteristics in subfreezing conditions, and (3) long life under arctic drilling conditions. Cementing in hydrate zones (which can occur in regions even significantly below the permafrost) may require special techniques, with even lower heat of hydration than now in use in permafrost [zones] free of hydrates. Special cements may be required to seal to the hydrate-rich zones. It is difficult to conceive of a perfect cement bond in a hydrate-rich zone if the cement produces heat in setting. This is *not* a trivial problem, but a serious technological challenge which should be met so that unexpected pressure changes at lower levels can be contained."

Discussion. Desirable characteristics for cements used against permafrost zones include short waiting-on-cement time, ability to set at existing borehole temperature, ample placement (thickening) time, sufficient strength development for well operations, and ability to set with low heat of hydration to prevent additional permafrost melting. Specific cement blends proposed for use in each Application for Permit to Drill shall be reviewed for their overall effectiveness. USGS believes that use of cements with low heat of hydration could only contribute toward the enhancement of the quality of a cement job. Also, a specific requirement for the cements used, to have heat of hydration of 15/18 Btu/lb, is no considered necessary. The present

requirement allows the lessees to improve the evolving technology of cementing in permafrost zones within broad acceptable guidelines.

Comments. Several respondents suggested that the requirement of the penultimate paragraph of subparagraph 3.3.1 of OCS Order No. 2, limiting the setting depth of conductor or surface casing in permafrost area, to less than 150 meters (492 feet) below the base of the permafrost, be deleted until such time as sufficient OCS wells have been drilled to determine the requirements needed to provide reasonable protection.

It was stated that experience from drilling in State waters of the Beaufort Sea indicated a discontinuous and much thinner permafrost thickness than onshore, and that as a result the freezeback and possible subsidence problems should be minimal in the OCS areas. It was suggested that in order to prevent imposition of irrevelant orders, those provisions of the OCS Orders dealing with permafrost "protection" be deleted until sufficient data are available from future arctic OCS wells to establish the necessity of such Orders.

Another commenter suggested that the first sentence of this subparagraph be changed to read, "In areas containing permafrost, the conductor or surface casing shall be set and cemented after drilling a maximum of 150 meters (492 feet) below the base of the permafrost, but at a depth that ensures good anchoring of the casing."

Discussion. In the Beaufort Sea OCS the depths to the base of the permafrost zone can only be ascertained by actual drilling. At the present time analyses of the data obtained from all available information points to a high probability of the existence of permafrost zones in the Beaufort Sea OCS and that these permafrost zones will be at shallower depths than in the adjacent onshore areas. Therefore, the USGS disagees with the suggestion that the OCS Orders provisions for dealing with permafrost "protection" should be deleted at this time.

However, the concerns expressed about the setting depth requirements for conductor and surface casing in permafrost whose depth may vary from site-to-site, have some merit, and the requirement was modified as follows: "In areas containing permafrost, lessees shall submit with their Application for Permit to Drill, casing programs that incorporate setting depths for conductor and surface casing based on anticipated depth of the permafrost at the proposed well location, and which utilize the current state-of-the-art methods to safely drill and set casing through the permafrost zones. The casing programs must provide for protection from thaw subsidence and freezeback effect, proper anchorage, and well control until the next string of casing is set. Minor deviations for the setting depths of conductor and surface casings in permafrost areas from those prescribed for permafrost-free areas in the preceding paragraph, may be permitted by the District Supervisor."

Comment. One commenter observed that some sections of the EA referred to "directional" surveys; however, the proposed Order No. 2 required only inclination survey on vertical wells. Order No. 2 defines vertical wells as those wells where inclination does not exceed 3 degrees from the vertical.

Discussion. This omission has been corrected in the EA.

Comment. One respondent commented on subparagraph 2.1.1 of Order No. 2 which requires the lessees to submit six types of specification/information. It was suggested that the following requirement be added to ensure that the proposed drilling unit will be capable of performing the planned drilling operations under arctic conditions.

"f. Plans, design drawings, and diagrams showing how systems under b, c, and d will be protected from subfreezing conditions, or the manufacturer's certification that equipment and safety systems will operate under subfreezing conditions."

Discussion. As required in subparagraph 2.1.5, *Subfreezing Operations,* lessees shall furnish evidence that the drilling equipment, drilling safety systems, and other associated equipment, and materials are suitable for operations under subfreezing conditions.

Also, paragraph 11 of OCS Order No. 2 requires the lessees to use the best available and safest technologies (BAST). For all equipment, procedures, or systems to be used, the lessee shall submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale why one alternative technology was selected in place of another. In view of the foregoing, the USGS had determined that the suggested addition will serve no useful purpose.

Comments. One commenter proposed that Arctic Operating Order No. 2 adopt the same requirement for surveys every 30 meters that is imposed by the State of Alaska. It was also proposed that the second paragraph of this section be amended to read as follows: "Continuous directional surveys giving both inclination and azimuth, shall be obtained on all directional wells at intervals not exceeding 30 meters (90 feet)."

Another commenter questioned the justification for increasing the number of surveys to improve the operator's ability to drill a successful relief well. It was stated, "This is false reasoning. Frequent surveys will result in a more detailed projection of a well's course. It does not necessarily follow that there will be significant improvement in the accuracy of the calculated versus actual well course. The well survey instruments are not 100% accurate and the calculation procedure to determine the well's course does not give results that are without some degree of error. The idea that more is better does not always apply and this implication of an increased chance of a successful relief well due to more frequent surveys does not consider the complexity and uncertainty inherent in relief well scenario."

Discussion. For vertical wells, the State of Alaska requires surveys every 500 feet. The requirement for surveys every 100 feet is applicable only when the surface location of a well is less than 660 feet from a lease line where ownership changes, or from any other vertical deviated well.

For all intentionally deviated wells, the State requires surveys at intervals not more than 100 feet apart.

However, all these requirements apply to production wells. The current requirements of OCS Order No. 2 permit collection of sufficient data to track the well course. Should a commercial discovery be made, the frequency of these surveys will be reviewed for the highly deviated production wells.

Comment. Another commenter suggested that the requirement for filing of a composite dipmeter directional survey on every well drilled could be very costly, and will increase the risk of blowouts/hole problems due to the additional time that the well will have open hole exposed to the wellbore.

Discussion. The requirements of Arctic OCS Order No. 2 apply only to exploratory and development wells. Should a commercial discovery be made, several provisions of this Order could be superseded or modified by the issuance of field drilling rules.

Comment. Several commenters suggested that the use of a directional tool which allows the operator to run a continuous survey while drilling be made a requirement.

Discussion. The present requirements permit the gathering of the needed data for an accurate tracking of the wellbore. USGS believes that the suggested

change would impose unwarranted economic burden on the lessee, considering the minimal benefits that would be obtained from the additional information. This suggestion was not adopted.

Comments. One respondent stated, "The analysis states that in order to protect against ice scouring of subsea blowout preventers, it is necessary to excavate deep depressions in the sea floor for the emplacement of such blowout preventers. We agree, but do not believe that this requirement is specified in Operating Order No. 2. Therefore, we recommend that it be specified in that Order."

Discussion. The USGS agrees with this recommendation and has added the following requirement to subparagraph 5.3:

"When a subsea blowout-preventer stack is to be used in an area which is subject to ice scour, the blowout-preventer stack shall be placed in an excavation (glory hole) with the top of the blowout-preventer stack below the deepest possible ice scour depth."

Comments. One commenter suggested that the requirement, "Mud temperatures shall be controlled to minimize heat loss to the permafrost and to mimimize thawing of the permafrost which can result in serious well problems while drilling through the permafrost," be deleted. It was argued, "Taken literally the proposed rule would require that mud systems be equipped with a means of maintaining mud temperatures at or below permafrost temperature. This would perhaps not require anything but a heat exchanger during the winter drilling activities, while in summer, elaborate refrigeration systems may be required. In either case, mixing and maintaining quality drilling mud is difficult at or near 0°C. Theories have been advanced on the effectiveness of various elaborate precautions to prevent thawing of the permafrost from drilling activities; however, experience in Prudhoe Bay Field and elsewhere has shown these precautions are largely unnecessary."

Another commenter stated, "the temperature of offshore permafrost is much closer to +32°F than is the temperature of onshore permafrost." It should be specified that, "the drilling fluid temperature be controlled to be below 32°F, to ensure that the melting is minimal. Heat generated by drilling may cause some melting, but mud temperature below +32°F will minimize this. The colder mud will also reduce the rate of conversion of gas hydrates into gaseous form, thus assisting in well control in hydrates zones."

Discussion. USGS rules do not require cooling of muds down to 32°F, only controlling of mud temperatures and use of mud systems that keep permafrost thaw to a minimum and conform to the current state-of-the-art in drilling through permafrost zones.

We agree that mixing and maintaining the quality of drilling mud is difficult at 32°F.

Neither of the suggested changes were considered necessary.

Comment. In comments on the EA, one respondent recommended that mud discharges should not be allowed into the marine environment.

Discussion. We disagree in part with the comment. The question of mud discharge was thoroughly studied in the preparation of the Beaufort Sea Joint Federal and State Lease Sale EIS and resulted in a lease stipulation which prohibits mud and cuttings discharge in areas with less than 10 meters water depth. Order No. 7 states the District Supervisor must give approval of mud discharge on a case-by-case basis. This gives the District Supervisor an opportunity to review the site-specific data before giving approval or disapproval on the application for mud discharge.

Comment. One respondent made the following comment: "The subsection on the mud program notes that approval of the District Supervisor is required prior to drilling activities. Since this is an environmental assessment, we believe it would have been worthwhile to consider a requirement for the use of less toxic mud components. We recommend that the USGS consider whether such a requirement may be feasible in the final Arctic OCS Orders."

Discussion. We do not accept this suggestion. Mud programs are designed with specific objectives in mind and unfortunately in order for the muds to have certain desired qualities toxic materials may have to be introduced into the mud program. This is the reason why Order No. 7 requires the District Supervisor's approval for mud disposal on a case-by-case basis. Where toxic materials are contained in the mud, the District Supervisor can require onshore disposal in an acceptable disposal area.

Comment. One respondent commented that the discussion of gas hydrates as a blowout cause is misleading, because there is no mention of routine monitoring and remedial measures that would serve to reduce this threat.

Discussion. In response to this comment we must first point out that there is a rather significant typographical error in this part of the Notice (45 FR 83875). The statement published which related to this comment read, "A rapid decomposition of gas hydrates caused by a drilling fluid that is too warm *would* cause a blowout by * * *." This statement should read, "* * * *could* cause a blowout by * * *."

With respect to the concern over the lack of discussion about monitoring and remedial measures, we refer the commenter to the EA section on the same page of the notice entitled "Blowout Preventer Equipment Requirements," and the paragraph that precedes the discussion which generated the comment. It is acknowledged that the purpose of the BOP is to provide a means for controlling a well when primary control has been lost due to insufficient mud hydrostatic pressure. The discussion of the use of drilling muds also acknowledges their critical well control function. We feel, therefore, that there is no need to repeat that discussion when discussing gas hydrates.

Comment. One commenter observed: "EA describes that enclosed mud-handling areas must be maintained at a negative (relative) pressure to prevent discharges from an adjacent area. It seems that the purpose is to prevent a discharge to, rather that from, an adjacent area."

Discussion. This is due to a typographical error. The requirement under subparagraph 6.4b Arctic OCS Order No. 2 on page 83896 of the **Federal Register** Notice does correctly require prevention of discharge from enclosed mud-handling areas to enclosed adjacent areas.

Comment. It was commented that the requirements of Order No. 2 conflict with those U.S. Coast Guard regulations. "The proposal requires enclosed mud-handling areas to have ventilation systems (1) capable of changing the air once each 2 minutes automatically on signal indicating the presence of gas, (2) that they will maintain a negative pressure relative to surrounding spaces, and (3) have pressure sensors, gas detectors, and explosion proof or ventilated electric equipment. Existing U.S. Coast Guard regulations for Mobile Offshore Drilling Units, 46 CFR Part 108.185(d), require that "Each ventilation system for enclosed classified locations must provide complete change of air every five minutes." Both requirements are designed to prevent the concentration of flammable gas reaching the lower explosive limit (LEL) of about five (5) percent. It is believed that the U.S. Coast Guard requirement applying to all mobile drilling units is practical and provides an adequate safety factor. The proposed requirement is a dual standard requiring unnecessary

expenditure, and it is not justified by the USGS."

Discussion. After review, the USGS agrees that subparagraph 6.4 of Order No. 2 should be modified. The requirement for changing the air every 2 minutes has been increased to 5 minutes to conform with U.S. Coast Guard requirements. This also conforms with the American Petroleum Institute Recommended Practices 14 C, First Edition, June 1974, Appendix C, Section C 1.3b.

Comments. Another comment received regarding the "enclosed mud-handling area" subparagraph of Order No. 2 stated:

"Requiring that the air in enclosed mud-handling areas be changed every two minutes instead of every five minutes as the U.S. Coast Guard requires would result in an unnecessarily high air heating load. Further, such high rates of ventilation may result in freezing of mud and instruments."

Discussion. The USGS does not agree with this statement, but has changed the ventilation rate to conform to U.S. Coast Guard requirements.

Comments. One commenter suggested that rather than relying on a potentially unreliable mechanical device to turn on the ventilation system, a manual system should be allowed.

Discussion. The suggestion for allowing the use of manual system to turn on the ventilation system was not adopted. We believe that properly maintained automatic systems are reliable. Manual systems rely on the presence of personnel. If the personnel are not present when the alarms are triggered, the ventilation system will not be activated. This would defeat the purpose of the requirement that combustible gases not be allowed to accumulate in enclosed mud-handling areas.

Comments. One respondent commented that our requirement in subparagraph 6.4 of Order No. 2 that ventilation systems be activated by detectors indicating "the presence of gas" is arbitrary. It was suggested that the requirement be revised so that ventilation system be activated by detectors indicating the presence of gas in concentrations of about 20 percent of the lower explosive limit.

Discussion. In response to this comment, we have revised subsection 6.4a. to require that gas detectors activate the ventilation system, when gas concentrations reach one percent of the total volume of air. This represents approximately 20 percent of the lower explosive limits for methane.

Comment. One commenter stated that the Arctic Orders should provide some standard level of protection to marine mammals for all potential arctic lease sale areas, suggesting that sighting of whales in the vicinity of drilling operations should be considered a criterion for curtailment of critical operations.

Discussion. The USGS disagrees. The USGS must wait until NOAA assembles some definitive information concerning the impacts of drilling operations on the whales. We do not anticipate significant problems during the two-year period. We believe that at the end of the two-year period, should a decision be made to allow year-around drilling, any mitigating measures can be addressed through a notice to lessees. In this way, NOAA can make recommendations site-specific, and the USGS can tackle the problems more effectively than by placing requirements in the OCS Orders.

Comment. One commenter stated, "The Arctic Order No. 2, Section 9 does not explicitly specify the monitoring of ice conditions during critical operations. But the commentary of Arctic Order No. 2, Sec. 9 (45 FR page 83876) says that continuous monitoring is required by the Order No. 2. We suggest that the Order No. 2, Section 9, be made to specify explicity that monitoring of ice conditions be done during critical operations."

Discussion. We agree. Subparagraph 2.1.4 of Order No. 2 states that lessees shall monitor ice conditions during operations. This is an overall requirement and applies to critical operations as well as normal operations.

Comment. One commenter states, "Critical drilling operation No. 7 [listed in OCS Order No. 2] describes moving the drilling vessel off location in an emergency. Remotely controlled anchor releases have been used with success in the Canadian Arctic. We should require systems of similar flexibility and responsiveness off Alaska. Used in conjunction with riser buoys, these could also aid in repositioning a rig."

Discussion. We believe the use of remote-controlled anchor releases has merit, but we do not believe we can require the use of such equipment in all cases. Our Orders require the operator to use BAST in all oil and gas operations. We can review and recommend, but we cannot force an operator to use a particular system or equipment as long as the operator is using equipment which conforms to the requirements of BAST.

Comment. One respondent commented on the discussion in the EA, stating that the lessees will burn off the produced oil or gas in a hot flame. It was suggested that an additional statement should be added to the EA discussion of Order No. 4 to the effect that the lessee may elect to burn off only the gas and use other means to dispose of the liquids. This option would provide more flexibility and would mitigate the environmental effect of "some air pollution."

Discussion. In response to that suggestion, we have added a statement to the EA acknowledging that the lessee may elect to burn off only the gas and dispose of the liquids at an approved onshore site.

Comment. It was commented that, "the requirement for the installation of subsurface safety devices seems to be more restrictive in some cases by requiring "approval of a setting depth . . . *so that it can be set below permafrost,*" (emphasis added). The need to set the SSV [subsurface safety valve] below the permafrost is based on outdated concepts. The proposed field rules for the Kuparuk will recommend that the SSV be set close to the surface within the permafrost zone. The setting depth for the SSV should not be arbitrarily restrictive, but should be based on the best available and safest technologies."

Discussion. The requirement in its present form specifies that "In permafrost areas, the setting depth of the subsurface-safety device shall be approved by the District Supervisor on a case-by-case basis." This provision allows the lessee to demonstrate the effective use of devices that function properly and efficiently in permafrost zones, even when the wells are shut in over prolonged periods. Such devices conform to BAST criteria. In the absence of such evidence, the placement of such devices below the permafrost will only be prudent. The suggested deletion was not adopted.

Comment. One commenter suggested that a requirement concerning a firewater system should be protected from subfreezing conditions and should be added to subparagraph 5.1.8 of Order No. 5.

Discussion. This suggestion was adopted in a modified form. The requirement quoted below is applicable tc all production equipment, production systems, and other associated equipment and was added as 1.1, *Subfreezing Operations,* in Order No. 5. Also, requirements pertaining to operations under subfreezing conditions in subparagraph 3.4 and paragraph 4 of Order No. 5 were removed as the following applies to all production systems, equipment, materials and operations.

1.1 *Subfreezing Operations.* Lessees shall furnish evidence that the production equipment, production safety systems, and other associated equipment and materials are suitable for operations under subfreezing conditions and that all equipment and operating procedures take into account floating ice, icing, and other extreme environmental conditions that may occur in the area.

Comment. It was suggested that the proposed requirement for "at least 30 minutes of run time for fire pumps during platform shut-in" was inadequate and that the same should be increased to 12 hours.

Discussion. We believe the present time requirement should provide enough time to control the fire or time to take other actions.

Comment. One commenter suggested that owing to the especially difficult operating conditions present in the Arctic, the USGS should impose strict controls over simutaneous operations, given the higher risks of accidents in these situations.

Discussion. The plans submitted by the lessees for simultaneous platform operations will be throughly reviewed for adequacy at the time they are submitted. Full consideration will be given to the environmental concerns. We feel that the present requirements of subparagraph 5.3 of OCS Order No. 5 adequately address the subject.

Comment. One commenter suggested that, based on frequent testing and calibration required in the North Sea, the USGS requirement of testing and recalibrating the gas detection systems every 6 months be changed to 3-month intervals.

Discussion. Since this suggestion should contribute toward enhancement of safety of arctic OCS operations in enclosed areas, the suggestion was adopted.

Comment. In response to the EA discussion of Order No. 7, one respondent stated that commercial fishing may not have reached its potential in the Chukchi Sea and Beaufort Sea but subsistence fishing was important and that we should change the phrase "commercial fishing" to "fishing" or "commercial and subsistence fishing."

Discussion. We agree. We have changed references from "commercial fishing" to "fishing" in Arctic OCS Orders Nos. 1 and 7 and in the EA.

Comment. One commenter suggests that we amend Order No. 7 to add a method for assessing and remedying damage from oil spills. The elements of the proposed method would include an evaluation program whereby the injured party may affix a value to those resources which are at risk as a result of the proposed development, and an administrative procedure and a fund formed or bond issued which may be held liable for the damage which may occur to the resource.

Discussion. The OCSLA has created an Offshore Oil Pollution Compensation Fund. U.S. Coast Guard regulations create the procedure for filing claims. See 33 CFR Parts 135 and 136. The Alaska Beaufort Sea Oilspill Response Body (ABSORB) organization is currently preparing a Coastline Sensitivity Atlas which will show locations and rankings of sensitive areas, along with specific methods to protect each area from an oil spill. This atlas should be ready by the end of 1981. We see no need to amend Order No. 7.

Comment. One commenter stated, "The disposal of solid chemical wastes on artificial gravel islands should be prohibited. The Orders only prohibit marine disposal, but do not address this issue. Because of the erosion of artificial islands, any wastes incorporated in the island will eventually end up in the water. This has been a serious problem in Canada and is prohibited by State Lease Stipulation No. 8."

Discussion. We feel that Federal Stipulation No. 4, which is identical to State Stipulation No. 8 and paragraph 1 and subparagraphs 1.1.1, 1.1.3a and b, 1.1.4, 1.2., 1.2.1, and 1.2.2 of Order No. 7, adequately address this subject.

Comment. One commenter stated, "It is unclear if the berm on an artifical island is likely to be constructed of gravel and, therefore, subject to redispersal in the environment either through natural erosion or intentional dismantling by man, it cannot be allowed to absorb oil. Therefore, it should be explicitly stated that the berm is to be lined with an impervious material which can be removed at abandonment without losing any remaining oil."

Another respondent recommended impervious barriers in drainage ditches as well.

Discussion. In response to these suggestions, subparagraph 1.1.3.2 of OCS Order No. 7 was revised to read: "On artifical islands, all vessels containing hydrocarbons shall be placed inside a berm lined with an impervious material. The volume enclosed by the berm shall be in excess of the volume of the vessels containing hydrocarbons. In addition, all drainage ditches shall be directed away from the drilling rig to a sump. The rig mat, the drainage ditches, and the sump will be lined with impervious material."

Comment. One commenter maintained "the requirement for a sump system which 'automatically' maintains the level in subparagraph 1.1.3 of Order No. 7, is unnecessary. There is no need for an automatic sump system for land drilling rigs, and this requirement will probably lead to inoperable systems being installed. Automatic systems around drilling rigs in the Arctic have a tendency to freeze and malfunction. We believe a system that is manually maintained reliable when used in conjunction with a land drilling rig on an artifical island."

Discussion. It was recognized that the first paragraph of the original subparagraph 1.1.3a is applicable to fixed platforms and structures and that the second paragraph was applicable to artificial islands. Therefore, subparagraph 1.1.3 was retitled and reorganized as set forth below. Revisions to the requirement for artificial islands are indicated in italics.

1.1.3 *Curbs, Gutters, and Drains*

1.1.3.1 *Fixed Platforms and Structures.* Curbs, gutters, drip pans, and drains shall be installed in all deck areas in a manner necessary to collect all contaminants and piped to a properly designed, operated, and maintained sump system which will automatically maintain the oil at a level sufficient to prevent discharge of oil into OCS waters. Sump piles shall not be used as processing devices to treat or skim liquids, but shall be used to collect treated produced water, treated sand, liquids from drip pans and deck drains, and as a final trap for hydrocarbon liquids in event of equipment upsets.

1.1.3.2 *Artificial Islands. On artificial islands, all vessels containing hydrocarbons shall be placed inside a berm lined with an impervious material. The volume enclosed by the berm shall be in excess of the volume of vessels containing hydrocarbons. In addition, all drainage ditches shall be directed away from the drilling rig to a sump. The rig mat, the drainage ditches and the sumps shall be lined with impervious material.*

1.1.3.3 *Mobile Drilling Units.* Curbs, gutters and drains which collect contaminants associated with the drilling operation on a mobile drilling unit shall be installed as required by subparagraph 1.1.3.1. Curbs, gutters, and drains which collect contaminants not associated with the drilling operation are subject to regulation by the U.S. Coast Guard.

Comment. One commenter recommended that a requirement be added to the proposed Orders that would provide for an unbiased review

by a qualified party of oil spill contingency plans submitted with exploration and development plans.

Discussion. The USGS recognizes the need to identify objective criteria by which to judge the adequacy of an oil spill contingency plan. In response to this need the USGS and the U.S. Coast Guard have developed a memorandum of understanding (MOU) which provides for an ongoing review by both agencies of oil spill contingency plans. This MOU is discussed in Part III.C.2.b. of the EA. Further, the oil spill contingency plan for any exploration or development proposal will be made available for review by interested parties. Timely comments or recommendations received on the contingency plans will be considered prior to approval or disapproval of the accompanying exploration or development plan.

Comment. One commenter stated,

"the ABSORB plan is widely available, and is a joint industry response for the Beaufort Joint Sale Area. Yet, the Arctic area OCS Orders apply to the entire Chukchi Sea and Beaufort Sea areas. (It is not yet clear that they will or will not be applied in the Bering Sea; this would depend upon the lease sale terms and conditions.) In any case, there is no method known to be effective for oil spill cleanup in the moving ice during breakup or during freezeup; this fact seems to not be mentioned in the environmental assessment. It is a serious deficiency insofar as it relates to the decision on whether to allow year-around drilling, a decision which must eventually be faced. On page 83873, one finds "* * * must anticipate ice conditions * * * during the execution of contingency plan * * *." Presumably this will require the offshore operator to continue an oil spill cleanup method in any ice conditions if he proposed to operate year-around.

Another commenters stated that the existing technology is inadequate to successfully contain and clean-up oil.

Discussion. After each sale area has been leased, it is anticipated that industry will either have ABSORB take in the additional area and modify the plan as needed or form another cooperative group to cover the new lease sale area.

We do not believe that effective oil spill cleanup methods in moving ice are unknown. Oil spill cleanup technology is constantly improving, and new techniques are being developed to cleanup spills under adverse arctic conditions. For the immediate future, Beaufort Sea Sale area operations are limited to a seasonal drilling period which is from November 1 to March 31. This seasonal drilling period will be in place for the first two years the lease is in effect. If, at the end of the two-year period, the resource agencies recommend that seasonal operations should be retained, the problem of cleanup during breakup or freezeup would really not be applicable. If year-round operations seem to be feasible at the end of the two-year period, cleanup capability would be reviewed again relative to the state-of-the-art of such technologies, before year-round operations would be permitted.

Comment. One commenter suggested that a new requirement be added for all drilling structures, i.e., ice islands and barges, which allow the escape of oil to the water column in the event of a loss of well control. "These drilling structures should to be surrounded by an impermeable barrier or be capable of being surrounded in a timely manner, if the need arises." It was argued that existing oil spill containment and cleanup technology are inadequate to contain or cleanup oil under arctic conditions, and in particular, oil under ice, oil in broken ice, and during breakup and freezeup. "An impermeable barrier would prevent severe environmental damage in the event of large oil spills, such as the Ixtoc I blowout in Mexico, and would facilitate cleanup."

Discussion. Oil spill contingency plans will be examined to ensure that they are adequate to control spills at the time proposed operations will be carried out. A blanket requirement that all drilling structures be surrounded by an impermeable barrier would be unnecessary and could be dangerous, because in the unlikely event of an oil blowout, collected oil (which could also be burning) could make the wellhead inaccessible for well control efforts. The primary objective should be to effectively contain and retrieve oil from marine environment, and this will be thoroughly examined at the time plans are submitted for review.

Comment. It was also suggested that exploratory drilling operations with a high probability of oil spills, i.e., well completions and testing, should not be scheduled during breakup or freezeup when access to the platform are severely restricted. This would significantly reduce the probability of severe environmental damage from large oil spills.

Discussion. For the first 2 years of the Beaufort Sea lease term, the drilling activities are already restricted to the period November 1 to March 31. The status of the developing oil spill containment and cleanup technology will be continuously monitored. Only when the oil spill contingency plans or their updates show that technology exists for containment and cleanup during breakup or freezeup, will such operations be permitted during those periods.

Comment. One commenter made the recommendation that "NOAA routinely reviews the listed areas of biological sensitivity to ensure that habitat NOAA is mandated to protect is included in the oil spill contingency plan."

Discussion. We agree. We believe NOAA should advise the USGS and the operator of in areas of biological sensitivity so that appropriate measures can be addressed in the annual review of the oil spill contingency plan.

Comment. One commenter suggested, "Order No. 8 should be expanded beyond engineering considerations to include biological habitat benefits that might help offset losses caused by construction. In particular, artificial islands can be sloped and surfaced to encourage use by local marine life, probably at relatively low cost."

Discussion. Artificial islands must be built according to engineering criteria subject to Platform Verification. If it is possible to construct these gravel islands so that the slopes and surfaces encourage the growth of marine biota, that secondary purpose will be encouraged. It is of primary importance that the islands be constructed according to sound engineering principles advocating structural integrity.

Comment. One commenter suggested, "the regulations should require that gravel islands be 'capable of withstanding the oceanographic, meteorological and ice conditions for the proposed area' and that this requirement should be further quantified. We further suggest that for any platform or structure, or any integral part of an installation where a collapse would have a major adverse effect on the environment and/or human safety, the environmental design load condition regarding wind, waves, currents, and ice should be taken as the environmental condition which has a defined probability of exceedance during the intended service life of the structure or installation."

Discussion. USGS feels that the existing requirements of OCS Order No. 8 adequately cover expressed concerns about the design, fabrication and verification of platforms and structures including artificial islands.

Subparagraph 1.1 of Arctic OCS Order No. 8 requires gravel islands to be designed, fabricated, and installed in accordance with the applicable provisions of the document entitled, "Requirements for Verifying the Structural Integrity of OCS Platforms," which identifies mandatory state-of-the-art performance standards. These

performance standards must be met in designing, fabricating, and installing gravel islands and any modification thereto. Environmental and loading information that have a bearing on design, installation and operation, such as wave heights and periods, current, vertical distribution of wind and gust velocities, water depth, storm and astronomical tide data, marine growth, snow and ice effects, and air and sea temperature, are already required to be submitted by the lessee in support of the design documentation of the gravel islands, by subparagraph 3.1.1.2 of Order No. 8. Also to be submitted is information on derived loads which consist of a listing of total design functional loads and loads due to wind, wave, ice and current force for longitudinal, transversal and diagonal approaches.

Comment. One respondent commented on subparagraph 1.4.2 of OCS Order No. 8, which requires all artificial islands, platforms, etc., to be under the provisions of the USGS document entitled, "Requirements for Verifying the Structural Integrity of OCS Platforms," which describes the third-party verification procedure for offshore structures. "There is no statement in the referenced document or in Proposed OCS Order 8 regarding the exemption of structures (such as gravel islands in shallow water inside the natural barrier islands) where design and construction are proven through experience. To remedy this, it is suggested that provisions be added to Proposed Arctic OCS Order 8 to make it clear that third party verification would only be required for advanced "state-of-the-art" structures and/or where a new extreme in environmental conditions is involved. This approach would make Proposed Arctic OCS Order 8 analogous to Gulf of Mexico OCS Order 8, which exempts all platforms, except those involving new design concepts and/or those to be installed in unusually hostile conditions."

Discussion. USGS disagrees with the suggested change. Design and construction of gravel islands are new to the Federal OCS in the arctic. Additionally, due to the extreme variation in environmental conditions in the area, no blanket exemption can be considered at this time. We fail to see any parallel between the maturity of the exploration/development/production activities in the arctic and the Gulf of Mexico.

Comment. One respondent commented that the provisions of OCS Order No. 8 do not adequately provide for an assessment of the environmental effects of new platforms which includes gravel islands.

Discussion. Arctic OCS Order No. 8 was not developed to address the environmental effects that gravel island construction would have on the environment. Rather, the proposed Order was developed to assure that structures placed on the OCS, including gravel islands, are designed in a manner that will withstand the forces of the natural environment.

The effects of gravel island construction on the environment and the effects of other activities described in an exploration plan will be analyzed in an EA required to be prepared for each exploration plan submitted for Beaufort Sea OCS leases. This fact is discussed in Part I.B. of the EA for the proposed Arctic OCS Orders.

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United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic, OCS Order No. 1—effective February 27, 1981

Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.37 and 250.54.

1. *Identification of Fixed Platforms or Structures.*

1.1 *Large Platforms and Structures.* Platforms and structures which have helicopter landing facilities shall be identified at two diagonal corners by a sign with letters and figures not less than 30 centimeters (12 inches) in height with the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the platform or structure is located.

d. The platform or structure designation.

The information shall be abbreviated as in the following example:

The Blank Oil Company operates "C" platform on Block 999 of the Salisbury Area. The identifying sign on the platform would indicate: BOC–SAL–999–C.

1.2 *Small Structures.* Small structures, including single well structures which do not have helicopter landing facilities, shall be identified with one sign only, with letters and figures not less than 7.6 centimeters (3 inches) in height.

The information shall be abbreviated as in the following example:

The Blank Oil Company operates well No. 1 which is equipped with a protective structure in Block 68 in the East Cameron Area. The identifying sign on the protective structure would show: BOC–E.C.–68–No. 1.

1.3 *Artifical Islands.* Artificial islands, such as gravel islands and ice islands, shall be identified as required by subparagraph 1.1 of this Order, except that only one sign is required to be installed in a prominent location on the island.

2. *Identification of Mobile Drilling Units.* Floating platforms, bottom-setting mobile rigs, and drilling ships shall be identified by one sign with letters and figures not less than 30 centimeters (12 inches) in height affixed to the derrick or the heliport so as to be visible to approaching traffic and shall contain the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the drilling unit is located.

d. The OCS lease number.

e. The well number.

3. *Identification of Wells.* The OCS lease and well numbers shall be painted on the wellhead or on a sign affixed to the wellhead of each singly completed well. In multiply completed wells, each completion shall be individually identified at the wellhead. All identifying signs shall be maintained in a legible condition.

4. *Identification of Subsea Objects.* Prior to the installation of subsea equipment required for lease operations, or in the event of the accidental sinking of an object, the owner shall report the submerged equipment or object to the appropriate U.S. Coast Guard District Commander subject to the following limitations. Reports are not required for equipment or objects that:

a. Are submerged in water depths greater than 305 meters (1,000 feet); or

b. Weigh 18 kilograms (40 pounds) or less and are of such shape or configuration that they are unlikely to snag or damage fishing devices; or

c. Are determined to be located on the seafloor within 46 meters (150 feet) of fixed structures on which approved aids to navigation are maintained.

The report shall contain the object's description, weight, dimensions, location, and the depth of water in which it is located. The U.S. Coast Guard will determine if it is a hazard to navigation and will detrmine whether it requires marking in accordance with 33 CFR 64.

5. *Marking of Equipment.* Whenever practicable, all materials, equipment, tools, containers, and items used on the OCS are to be properly color-coded, stamped, or labled with the owner's identification prior to actual use. For oil and gas operations, this means the owner's identification, as approved or prescribed by the Director, is to be placed upon all materials, cable, equipment, tools, containers, and other objects which could be freed and lost overboard from rigs, platforms, or supply vessels, and are of sufficient size or are of such a nature that they could be expected to interfere with fishing gear if dropped overboard.

6. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Approved:

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic OCS Order No. 2—Effective February 27, 1981

Drilling Operations

This order is issued pursuant to the authority prescribed in 30 CFR 250.10 and 250.11. All exploratory and development wells drilled for oil and gas shall be drilled in accordance with 30 CFR 250.30, 250.34, 250.36, 240.38, 250.40, 240.41, and the provisions of this Order except for those provisions superseded by the issuance of field drilling rules.

This order requires the lessee to submit plans, applications, data, and other information. In all cases where the lessee(s) has(have) identified another party as designated lease operater in accordance with 30 CFR 250.31 and where the term "operator" is defined in accordance with 30 CFR 250.2(gg), the required information may be submitted by the designated lease operator.

In addition to the requirements of this Order, the lessee shall comply with the requirements of paragraph 9, *Requirements for Drilling Rigs,* of OCS Order No. 5.

1. *Plans and Applications.*

1.1 *Exploration Plan and Development and Production Plan.*

In accordance with 30 CFR 250.34, the lessee shall submit Exploration Plans and Development and Production Plans to the Deputy Conservation Manager (DCM), Offshore Field Operations, for approval. All wells drilled under the provision of this Order shall be included in the appropriate plan. In addition, the Exploration Plans and Devleopment and Production Plans shall include provisions to deal with emergency situations involving:

a. A means of drilling a relief well should a blowout occur.

b. Loss or disablement of a drilling unit or a drilling rig.

c. Loss of or damage to support craft.

d. Hazards unique to the site of the drilling operations, including conditions such as solid ice cover, freezeup and breakup.

1.2 *Application for Permit To Drill.* Prior to commencing drilling under an approved Exploration Plan or a Development and Production Plan, the lessee shall file, in triplicate, an Application for Permit to Drill (Form 9–331 C) with the District Supervisor for approval. Additionally, DCM, Offshore Field Operations, will prescribe the number of public information copies to be submitted.

2. *Drilling from Fixed Platforms and Mobile Drilling Units.*

2.1 *General Requirements.*

2.1.1 *Fitness of Drilling Unit.* All fixed and mobile drilling units shall be capable of withstanding the oceanographic, meteorological, and ice conditions for the proposed area of operations. The lessee shall submit with the Exploration Plan or Development and Production Plan evidence to the DCM, Offshore Field Operations, of the fitness of the drilling unit to perform the planned drilling operation.

This evidence shall include the following specifications or other information as requested by the District Supervisor:

a. The rated capacity of all major drilling equipment.

b. Drilling safety systems.

c. Firefighting equipment.

d. Pollution-prevention equipment associated with the drilling operation.

3. A schematic diagram of the drilling unit.

f. A "Critical Operations and Curtailmant Plan" as described in paragraph 9 of this Order.

After a drilling unit has been approved for use in an area, the information listed above need not be resubmitted unless required by the DCM, Offshore Field Operations, or there are changes in equipment which affect the rated capability of the unit.

2.1.2 *Pre-Drilling Inspection.* Prior to commencing operations in an OCS area, all fixed drilling platforms and mobile drilling units shall be made available for a complete inspection by the District Supervisor.

2.1.3 *Well-Site Surveys.* Lessees shall submit a shallow geologic hazards report, and conduct such shallow geologic hazard surveys or other surveys as required by the DCM, Offshore Field Operations. The results of these surveys and an analysis of the geologic hazards shall be furnished to the District Supervisor. All data obtained from the surveys and all geophysical data relating to shallow hazards shall be furnished upon request to the District Supervisor. When requested, this data shall include sediment and seabed data, e.g., seabed profiles, sediment consistency, allowable bearing and sliding loads, and nearby potential seabed hazards, i.e., sand waves, slumps, mud slides, permafrost, and deposits of frozen gas hydrates.

2.1.4 *Oceanographic, Meteorological, and Performance Data.* Where such information is not readily available, lessees shall collect and report oceanographic, meteorological, performance data, and monitor ice conditions during the period of operations. The type of information collected, method of collection, and report requirements will be as specified by the DCM, Offshore Field Operations.

2.1.5 *Subfreezing Operations.* Lessees shall furnish evidence that the drilling equipment, drilling safety systems, and other associated equipment and materials are suitable for operations under subfreezing conditions.

2.2 *Mobile Drilling Units.* Applications for drilling from mobile drilling units shall include the following:

a. A listing of the maximum environmental and operational conditions used for the design.

b. A listing of the regional maximum environmental conditions, including wave, wind, current, ice loading, icing, storm surges, and seismic motion, and of the unusual site-specific environmental conditions anticipated to be encountered at the drill site during the drilling operations.

c. Current American Bureau of Shipping Classification, U.S. Coast Guard Certificate of Inspection, or other appropriate classifications, with operational limitations.

2.3 *Fixed Drilling Platforms.* Applications for installations of fixed drilling platforms or structures, including artificial islands, shall be submitted in accordance with OCS Order No. 8. Mobile drilling units which have their jacking equipment removed, or have been otherwise immobilized, will be considered fixed drilling platforms, and applications shall also be submitted in accordance with OCS Order No. 8.

3. *Well Casing and Cementing.*

3.1 *General Requirements.* All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application for Permit to Drill shall include the casing design safety factors for collapse, tension, and burst. In addition, the Application for Permit to Drill must include a proposal to fill all annuli within permafrost zones with cement or a liquid with a freezing point below the minimum permafrost temperature to prevent internal freezeback. The cement used to cement through permafrost zones shall be designed to set before freezing and shall have a low heat of hydration so as not to thaw frozen formations. Wells drilled in areas which are underlain by freshwater aquifers shall have casing programs which are designed to protect the freshwater zones. In cases where cement has filled the annular space back to the ocean floor, upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural, conductor, surface, intermediate, and production casing. If there are indication of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment on the surface, intermediate, and production casing strings), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicated inadequate cementing, the lessee shall recement or take other actions as approved by the District Supervisor. The lessee shall verify the adequacy of the remedial cementing operations as required by the District Supervisor.

The design criteria considered for all wells shall be submitted with the Application for Permit to Drill. The criteria to be considered shall include all pertinent factors for well control, such as:

a. Formation fracture gradients.

b. Formation pressure.

c. Anticipated surface pressure.*

d. Casing setting depths.

e. Permafrost zones.

The lessee shall utilize appropriate drilling technolgy and state-of-the-art methods, such as drilling-rate evaluation, shale-density analysis, or other appropriate methods in order to enhance the evaluations of conditions of abnormal pressure and to minimize the potential for the well to flow or kick.

All casing, except drive pipe or structural casing, shall be new pipe which meets or exceeds American Petroleum Institute (API) standards, or reconditioned used pipe that has been tested to assure that it will meet or exceed API standards for new pipe. If casing to be used is not fabricated to API standards, the yield strengths of the casing shall be included on the Application for Permit to Drill (Form 9–331 C), provided these specifications are not on file with the USGS.

3.2 *Drive or Structural Casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth of 30 meters (98 feet) below the ocean floor or to other depths, as may be required or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, the drilling fluid shall be of a type tthat is in compliance with the liquid disposal requirement of OCS order No. 7, and a quantity of cement sufficient fo fill the annular space of the drilled hole shall be used.

3.3 *Conductor and Surface Casing Setting and Cementing Requirements.*

3.3.1 *Conductor and Surface Casing Setting Depths.* Casing design and

* Anticipated surface pressure is defined as the surface well pressure which can reasonably be expected to be exerted upon a casing string and its related wellhead equipment. In the calculation of anticipated surface pressure, the lessee shall take into account the drilling, completion, and producing conditions. He shall consider mud densities to be used below various casing strings, fracture gradients of the exposed formations, casing setting depths, total well depth, formation fluid type, and other pertinent conditions. Considerations for calculating anticipated surface pressure may vary for each segment of the well. The lessee shall include as a part of the statement of anticipated surface pressure the calculations used to determine this pressure during the drilling phase and the completion phase, including the anticipated surface pressure used for production string design.

setting depths shall be based upon all engineering and geologic factors, including the presence or absence of hydrocargons, other potential hazards, and water depths. These strings of casing shall be set at the depths specified, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; however, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. The District Supervisor may prescribe the setting depths for those wells which may encounter abnormal pressure conditions.

In permafrost-free areas, conductor casing setting depths shall be between 91 meters (298 feet) and 305 meters (1,000 feet) True Vertical Depth (TVD) below the ocean floor, and surface casing setting depths shall be between 305 meters (1,000 feet) and 1,400 meters (4,593 feet) TVD below the ocean floor.

In areas containing permafrost, lessees shall submit with their Applications for Permit to Drill, casing programs that incorporate setting depths for conductor and surface casing based on the anticipated depth of the permafrost at the proposed well location, and which utilize the current state-of-the-art methods to safely drill and set casing through the permafrost zones. The casing programs must provide protection from thaw subsidence and freezeback effect, proper anchorage, and well control until the next string of casing is set. Minor deviations for the setting depths of conductor and surface casings in permafrost areas from those prescribed for permafrost-free areas in the preceding paragraph, may be permitted by the District Supervisor.

Engineering, geophysical, and geologic data used to substantiate the proposed setting depths of the conductor and surface casings (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

3.3.2 *Conductor Casing Cementing Requirements.*

3.3.2.1 *Drilling from Artificial Islands.* When drilling from artificial islands, conductor casing shall be cemented with a quantity of cement sufficient to fill the calculated annular space back to the surface. Cement fill to surface shall be verified by the observation of cement returns. Upon approval by the District Supervisor, the cement may be washed out of displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment.

3.3.2.2. *Drilling from Floating Drilling Rigs.* When drilling from floating drilling rigs, conductor casing shall be cemented with a quantity of cement sufficient to fill the calculated annular space up to the top of the casing. Cement fill to the top of the casing shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible or possible, the method of verifying the cement fill shall be approved by the District Supervisor. Upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment.

3.3.3 *Surface Casing Cementing Requirements.* Surface casing shall be cemented with a quantity of cement sufficient to protect all freshwater zones, to provide well control until the next string of casing is set, and with sufficient cement to fill the calculated annular space to the top of the permafrost zone, and with the cement fill at least 60 meters (197 feet) inside the conductor casing, or as approved by the District Supervisor. Any portion of the annulus opposite a permafrost zone which is not protected by cement shall be filled with a liquid with a freezing point below the minimum permafrost temperature to prevent internal freezeback.

For floating drilling operations that use a one-stack blowout-preventer (BOP) system, a lesser volume of cement is permissible to prevent sealing the annular space between the conductor casing and surface casing, when approved by the District Supervisor. Any annular space open to the drilled hole shall be sealed in accordance with the requirements in Order No. 3 upon abandonment.

After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as approved by the District Supervisor. The results of this test and any subsequent tests of the formation shall be recorded on the driller's report and used to determine the depth and maximum mud weight to be used in the intermediate hole.

3.4 *Intermediate Casing Setting and Cementing Requirements.* One or more strings of intermediate casing shall be set when required by anticipated abnormal pressure, mud weight, sediment, and other well conditions. The setting depth for intermediate casing shall be based on the pressure tests of the exposed formation below the surface casing shoe or on subsequent pressure tests. After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as approved by the District Supervisor. The results of this test and any subsequent tests of the formation shall be recorded on the driller's report and used to determine the depth and maximum mud weight to be used in the hole below the intermediate-casing string.

A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 150 meters (492 feet) above the zones to be isolated or 150 meters (492 feet) above the casing shoe in cases where zonal coverage is not required. Any portion of the annulus opposite a permafrost zone not protected by cement must be filled with a liquid which has a freezing point below the minimum permafrost temperature to prevent internal freezeback.

If a liner is used as an intermediate string, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for intermediate casing. The liner shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and the next larger string has been achieved. The test shall be recorded on the driller's report. If the test indicates an improper seal, the top of the liner shall be squeeze cemented. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

3.5 *Production Casing.* Production casing shall be set before completing the well for production. It shall be cemented in a manner necessary to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a calculated volume sufficient to fill the annular space at least 150 meters (492 feet) above the uppermost hydrocarbon

zone must be used. Open-hold and slotted-liner completions are permitted when approved by the District Supervisor. Any portion of the annulus opposite a permafrost zone not protected by cement must be filled with a liquid which has a freezing point below the permafrost temperature to prevent internal freezeback.

When a liner is used as production casing below intermediate casing, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for the production casing. Testing of the seal between the liner top and the next larger string shall be conducted as in the case of intermediate liners and recorded on the driller's report. If the test indicates an improper seal, the top of the liner shall be squeeze cemented.

3.6 *Pressure-Testing of Casing.* Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure-tested as shown in the table below. The test pressure shall not exceed 70 percent of the internal yield pressure of the casing. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing tested again. The above procedures shall be repeated until a satisfactory test is obtained.

Casing	Minimum surface pressure
Conductor	1,400 kilopascals (kPa) (203 psi).
Surface	6,900 kPa (1,000 psi)*.
Intermediate, Liner, and Production.	10,400 kPa (1,508 psi)* or 5 kPa/m (0.22 psi/ft.) whichever is greater.

*Must not exceed 70 percent of the minimum internal yield pressure. In the event of prolonged drill pipe operations which could cause damage to the casing, the casing shall be pressure-tested, calipered, or otherwise evaluated, as approved by the District Supervisor.

After cementing any of the above strings, drilling shall not be resumed until there has been a time lapse of 8 hours under pressure for the conductor casing string or 12 hours under pressure for all other strings. Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used. All casing pressure tests shall be recorded on the driller's report.

In addition to the time lapse stated above, sufficient time must elapse to allow the bottom 153 meters (502 feet) of annular cement fill, or total length of annular cement fill, if less, to attain a compressive strength of at least 3,448 kPa (500 psi), or, as approved by the District Supervisor, before drilling resumes.

The typical performance data for the particular cement mix used in the well shall be used to determine the time lapse required.

4. *Directional Surveys.* Wells are considered vertical if inclination does not exceed an average of 3 degrees from the vertical. Inclinational surveys shall be obtained on all vertical wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling.

Wells are considered directional if inclination exceeds an average of 3 degrees from the vertical. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling and at intervals not exceeding 30 meters (98 feet) in all planned angle-change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 150 meters (492 feet) prior to, or upon, setting surface or intermediate casing, liners, and at total depth. Composite directional surveys shall be filed with the District Supervisor. The interval shown will be from the bottom of conductor casing or, in the absence of conductor casing, from the bottom of drive or structural casing to total depth. In calculating all surveys, a correction from true north to Universal Transverse Mercator Grid north or Lambert Grid north shall be made after making the magnetic-to-true-north correction. A composite dipmeter directional survey including a listing of the directionally computed inclinations and azimuths on a well classified as vertical will be acceptable as fulfilling the applicable requirements of this paragraph.

5. *Blowout-Preventer (BOP) Equipment Requirements.*

5.1 *General Requirements.* Blowout preventers and related well-control equipment shall be installed, used, maintained, and tested in a manner necessary to assure well control.

5.1.1 *BOP Equipment.* Blowout-preventer equipment shall consist of an annular preventer and the specified number of ram-type preventers. The pipe rams shall be of proper size to fit the drill pipe in use. The working pressure of any blowout preventer shall exceed the anticipated surface pressure to which it may be subjected, except that the working pressure of the annular preventer need not exceed 34,475 kPa (5,000 psi), unless a higher working pressure is required by the District Supervisor. When the anticipated surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with the Application for Permit to Drill a well-control procedure which indicates how the annular preventer will be utilized and the pressure limitations which will be applied during each mode of pressure control.

All blow-out preventer systems shall be equipped with:

a. A hydraulic actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minumum pressure of 1,400 kPa (203 psi) above the precharge pressure. An accumulator backup system, supplied by a secondary power source independent from the primary power source, shall be provided with sufficient capacity to close all blowout preventers and hold them closed. Locking devices shall be provided on the ram-type preventers. The method of BOP actuation control, such as hydraulic, acoustic, or other methods, shall be described and included in the Application for Permit to Drill.

b. At least one operable remote blowout-preventer-control station, in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

c. A drilling spool with side outlets, if side outlets are not provided in the BOP body, to provide for separate kill and choke lines.

d. A kill line equipped with 2 kill-line valves is required. The master valve shall be located adjacent to the BOP. This valve shall not normally be used for opening or closing on flowing fluid. The second valve shall be located adjacent to the master valve. This valve shall be used as the control valve.

e. A fill-up line above the uppermost preventer.

f. A choke manifold equipped in accordance with "API Recommended Practice for Blowout-Prevention Equipment Systems," API RP 53, First Edition, February 1976, reissued February 1978, Sections 3A and 3B, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

g. Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold shall have a pressure rating at least equal to the anticipated surface pressure.

h. A wellhead assembly with a working pressure at least equal to the anticipated surface pressure.

5.1.2 *Auxiliary Equipment.* The following auxiliary equipment shall be provided and maintained in operable condition at all times:

a. A kelly cock shall be installed below the swivel, and an essentially full-opening valve of such design that it can be run through blowout preventers, shall be installed at the bottom of the kelly. A wrench to fit each valve shall be stored in a conspicuous location readily accessible to the drilling crew.

b. An inside blowout preventer and an essentially full-opening drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string.

c. A safety valve shall be available on the rig floor assembled with the proper connection to fit the casing string that is being run in the hole at the time.

5.1.3 *Subfreezing Operations.* The blowout preventers and related control equipment shall be suitable for operations in those areas which are subject to subfreezing conditions.

5.2 *Subsea BOP Requirements.* The minimum requirements for drilling below the casing strings for subsea blowout-preventer stacks are tabulated below:

Drive or structural	See Notes 1 and 2.
Conductor	1—Annular.
	1—Diverter System 3 and 4.
Surface	1—Annular.
	2—Pipe Rams.
	1—Blind Shear Ram.
Intermediate	1—Annular.
	2—Pipe Rams 5.
	1—Blind Shear Ram.

Notes

1. When drilling fluids are circulated to the drilling vessel, a diverter system as described in subparagraphs 5.4.1 shall be installed on top of the marine riser.

2. If returns to the surface cannot be established, refer to subparagraphs 5.4.2.

3. The choke and kill lines or equivalent vent lines, equipped with necessary connections and fittings, can be used for diversion, if approved by the District Supervisor, or an annular preventer or pressure-rotating, packoff-type head, equipped with suitable diversion lines, shall be installed on top of the marine riser.

4. To be installed on top of the marine riser. The diverter system shall provide, as a minimum, two 15-centimeter (6-inch) internal diameter lines and full-opening valves.

5. When a tapered drill string is in use, the BOP stack shall be equipped with one of the following pipe ram configurations:

a. Two (2) sets of pipe rams for the larger size string and one (1) set for the smaller size string of drill pipe.

b. Two (2) sets of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

c. Two (2) sets of variable bore pipe rams to fit both sizes of pipe.

d. One (1) set of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

e. One (1) set of pipe rams for the larger size string, one (1) set of pipe rams for the smaller pipe, and one (1) set of variable bore pipe rams to fit both sizes of pipe.

Subsea blowout-preventer stacks shall be equipped with blind shear rams. A subsea accumulator or a suitable alternate approved by the District Supervisor is required to provide fast closure of the preventers and to operate all critical functions in case of loss of power fluid connection to the surface. The blowout-preventer system shall include dual pod control systems in accordance with API RP 53, First Edition, February 1976, reissued February 1978, Subsection 5.B.13, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Prior to the removal of the marine riser for installing casing, the riser shall be displaced with seawater. Sufficient hydrostatic head shall be maintained within the well bore to compensate for the reduction in head and to maintain a safe well condition. If repair or replacement of the blowout-preventer stack is necessary after installation, this work shall be accomplished after casing has been cemented prior to drilling out the casing shoe or by setting a cement or bridge plug or storm packer to assure safe well conditions.

When a subsea blowout-preventer stack is to be used in an area which is subject to ice scour, the blowout-preventer stack shall be placed in an excavation (glory hole) with the top of the blowout-preventer stack below the deepest possible ice scour depth.

5.3 *Surface BOP Requirements.* The minimum requirements for drilling below the casing strings for conventional surface blowout-preventer stacks are tabulated below:

Drive or Structural:
1—Annular
1—Diverter System [1]
Conductor:
1—Annular
1—Diverter System [1]
Surface:
1—Annular
2—Pipe Rams
1—Blind Ram
Intermediate:
1—Annular
2—Pipe Rams [2]
1—Blind Ram

5.4 *Drive Pipe or Structural Casing BOP Requirements.*

5.4.1 *Drilling Operations from Bottom-Supported Rigs.* Before drilling below this string with a bottom-setting rig, a diverter system utilizing an annular-type preventer and related equipment shall be installed for circulating the drilling fluid to the drilling structure. The diverter system shall be equipped with remote-control valves in the main and diverter flow lines that can be operated from the control panel prior to shutting in the well. The diverter lines shall vent in different directions to permit downwind diversion. A schematic diagram and operational procedure for the diverter system shall be submitted with the Application for Permit to Drill (Form 9–331 C) to the District Supervisor for approval.

5.4.2 *Floating Drilling Operations.* In drilling operations where a floating or semisubmersible type of drilling vessel is used and formation competency at the structural casing setting depth is not adequate to permit circulation of drilling fluids to the vessel while drilling the conductor hole, a program which provides for safety in these operations shall be described and submitted to the District Supervisor for approval. This program shall include all known pertinent information, including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, a schematic diagram indicating the equipment to be installed from the rotary table to the proposed conductor-casing seat, and a contingency plan for moving off location.

5.5 *Conductor Casing.* Before drilling below this string, at least one remote-controlled, annular-type blowout preventer shall be installed. A diverter system and other equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed as described in subparagraph 5.4.1.

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[1] The diverter system shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves. The flowpath from the BOP to the branch point of diverter lines in new systems shall have a minimum internal diameter of 15 centimeters (6 inches).

[2] When a tapered drill string is in use, the BOP stack shall be equipped with one of the following pipe ram configurations:

a. Two (2) sets of pipe rams for the larger size string and one (1) set for the smaller size string of drill pipe.

b. Two (2) sets of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

c. Two (2) sets of variable bore pipe rams to fit both sizes of pipe.

d. Two (2) sets of pipe rams for the larger size string. The blind ram cavity shall be equipped with blind shear rams and the blind ram actuator shall be converted to operate the blind shear rams. A crossover sub to the larger size pipe shall be readily available on the rig floor.

e. One (1) set of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

f. One (1) set of pipe rams for the larger size string, one (1) set of pipe rams for the smaller pipe, and one (1) set of variable bore pipe rams to fit both sizes of pipe.

5.6 *Surface and Intermediate Casing.* Before drilling below these strings, the blowout-preventer system shall consist of at least four remote-controlled, hydraulically operated blowout preventers including at lease two equipped with pipe rams, one with blind rams, and one annular type. Subsea blowout-preventer stacks used with floating drilling vessels shall include one set of blind shear rams.

5.7 *Testing of BOP Systems.* Prior to conducting high-pressure tests, all BOPs shall be tested to a low pressure of 1,400 to 2,000 kPa (203 to 290 psi). All BOP tests shall be recorded in the driller's report.

5.7.1 *BOP Testing Frequency.* Surface and subsea BOP stacks shall be tested as follows:

a. When installed.

b. Before drilling out after each string of casing has been set.

c. At least once each week, but not exceeding 7 days between tests, alternating between control stations. If either control system is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between blowout-preventer tests is allowed when well operations prevent testing and remedial efforts are being performed, provided the tests will be conducted as soon as possible before normal operations resume, and the reason for postponing testing is entered into the report. Well operations which prevent testing are stuck drill pipe and pressure-control operations. Testing shall be at staggered intervals to allow each drilling crew to operate the equipment.

The weekly test is not required for blind and blind shear rams. These rams need only be tested prior to drilling out after each casing string has been set.

d. Following repairs that require disconnecting a pressure seal in the assembly.

5.7.2 *Pressure Testing Surface BOP Systems.* Ram-type BOPs and related control equipment including the choke manifold shall be tested at the anticipated surface pressure or at 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. The annular-type BOP shall be tested at 70 percent of its rated working pressure or 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser.

5.7.3 *Pressure Testing Subsea BOP Systems.* Subsea BOPs and all related well-control equipment shall be stump tested at the surface with water to the anticipated surface pressure, except that the annular-type BOP shall not be tested above 70 percent of its rated working pressure. After the installation of the BOP stack on the sea floor, the control equipment and ram-type BOPs shall be tested as required under subparagraph 5.7.2.

5.7.4 *Actuation of Auxiliary Well-Control Equipment.* In conjunction with the weekly pressure test of surface and subsea BOP systems, auxiliary well-control equipment such as choke manifold valves, kelly cocks, and drill pipe safety valves shall be actuated. Casing safety valves shall be actuated prior to running casing.

5.8 *Inspection and Maintenance.* All BOP systems, marine risers, and associated equipment shall be inspected and maintained to assure that the equipment will function properly. The manufacturers' recommended inspection and maintenance procedures are acceptable as guidelines in complying with this requirement. The BOP systems and marine risers shall be visually inspected at least once each day if the weather and sea conditions permit the inspection. Inspection of subsea installations may be accomplished by the use of television equipment.

5.9 *Blowout-Preventer Drills.* All drilling personnel shall be indoctrinated in blowout-preventer drills and be familiar with the blowout-preventer equipment before starting work on the well. A blowout-preventer drill shall be conducted for each drilling crew in accordance with the well-control drill requirements of the U.S. Geological Survey (USGS) Outer Continental Shelf Standard "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T 1), First Edition, December 1977, or subsequent revisions thereto. A BOP drill may be required by a USGS designated representative at any time during the drilling operation, after notifying and consulting with the lessee's senior representative present.

All BOP drills shall be recorded in the driller's report.

6. *Mud Program.* The characteristics, use, and testing of drilling mud and the implementation of related drilling procedures shall be designed to prevent the loss of well control. Sufficient quantities of mud materials shall be maintained readily accessible for use at all times to assure well control.

Mud temperatures shall be controlled to minimize heat loss to the permafrost and to minimize thawing of the permafrost which can result in serious well problems while drilling through the permafrost. To insure maximum safety, hydrate zones shall be aniticipated and diagnosed quickly, and drilled using the latest state-of-the-art methods. Provided that the hydrate zones are adequately protected, drilling can continue of a site specific basis without the need to control the mud temperatures thereafter.

6.1 *Mud Control.* Before starting out of the hole with drill pipe, the mud shall be properly conditioned. Proper conditioning requires either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, or proper documentation in the driller's report prior to pulling the drill pipe as follows:

a. There is no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole.

b. The weight of the returning mud is essentially the same as the weight of the mud entering the hole. In the event that the returning mud is lighter than the entering mud by a weight differential equal to or greater than 0.2 pound per gallon, the mud shall be circulated until the annular volume is displaced, and the mud properties shall be checked for the influx of gas or liquid.

c. Other mud properties recorded on the daily drilling report are within the specified ranges required by the mud program.

When the mud in the hole is circulated, the driller's report shall be so noted.

When coming out of the hole with drill pipe, the annulus shall be filled with mud before the change in mud level decreases the hydrostatic pressure 517 kPa (75 psi) or every 5 stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent mud volume shall be calculated and posted. A mechanical, volumetric, or electronic device for measuring the amount of mud required to fill the hole shall be utilized.

When there is an indication of swabbing or influx of formation fluids, the necessary safety devices and action shall be employed to control the well. The mud shall be circulated and conditioned, on or near bottom, unless well or mud conditions prevent running the drill pipe back to the bottom.

The maximum pressure which can be tolerated on each casing string shall be posted near the driller's console.

An operable gas separator shall be installed in the mud system prior to commencement of drilling operations. The separator shall be maintained for use throughout the drilling and completion of the well.

The mud in the hole shall be circulated or reverse-circulated prior to pulling the drill-stem test tools from the hole.

6.2 *Mud Testing and Monitoring Equipment.* Mud-testing equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed once each tour, or more frequently, as conditions warrant. Such tests shall be conducted in accordance with procedures outlined in "API Recommended Practice for Standard Procedure for Testing Drilling Fluids," API RP 13B, Seventh Edition, April 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. The results of the tests shall be recorded and maintained at the drill site.

The following mud-system monitoring equipment shall be installed with derrick floor indicators and used when mud returns are established and throughout subsequent drilling operations:

a. Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include both a visual and an audio warning device.

b. Mud-volume measuring device for accurately determining mud volumes required to fill the hole on trips.

c. Mud-return indicator to determine that returns essentially equal the pump discharge rate.

d. Gas-detecting equipment to monitor the drilling mud returns, with indictors located in the mud-logging compartment or on the derrick floor. If the indicators are in the mud-logging compartment, there shall be a means of immediate communications with the rig floor, and the equipment shall be continually manned.

6.3 *Mud-Quantities.* The lessee shall include, with his Application for Permit to Drill, a tabulation of well depth versus minimum quantities of mud material, including weighting material, to be maintained at the drill site to assure well control.

When the mud quantity required exceeds the storage capacity of the drilling facility, the lessee shall maintain maximum mud inventories and must receive approval from the District Supervisor of the lessee's plans to resupply mud inventories in the event of an emergency. The plan shall include an estimate of the time required for delivery of the mud supplies.

Daily inventories of mud materials, including weighting material, shall be recorded and maintained at the well site. Drilling operations shall be suspended in the absence of minimum quantities of mud material specified in the table or as modified in the approved plan.

6.4 *Safety Precautions in Enclosed Mud-Handling Areas.* All enclosed mud-handling areas where dangerous concentrations of combustible gases may accumulate shall be equipped with a ventilation system and with gas monitors. These enclosed areas shall be:

a. Ventilated with high-capacity, mechanical ventilation systems capable of changing the air once every 5 minutes on signal from a gas detector or gas detectors, that are operative at all times, indicating the presence of one percent of gas, by volume.

b. Maintained at a negative pressure relative to the surrounding areas where discharge to an adjacent enclosed area may be hazardous. The negative pressure areas are to be protected with a pressure sensitive alarm.

c. Fitted with gas detectors and alarms.

d. Equipped with electrical equipment of the "explosion proof" type. Alternatively, the equipment may be pressurized to prevent in ingress of explosive gases, and where air is used for pressurizing, the air intake shall be located outside of, and as far as practicable from, hazardous areas.

7. *Supervision, Surveillance, and Training.*

7.1 *Supervision.* A representative of the lessee shall provide onsite supervison of drilling operations on a 24-hour basis.

7.2 *Surveillance.* From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling cew or the toolpusher shall maintain rig-floor surveillance continuously, unless the well is secured with blowout preventers, bridge plugs, storm packer, or cement plugs.

7.3 *Training.* Prior to conducting any drilling operations, lessee and drilling contractor personnel shall be trained and qualified in accordance with the provisions of the USGS Outer Continental Shelf Standard "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T 1), First Edition, December 1977, or subsequent revisions thereto.

In order to maintain qualification, any driller, toolpusher, or operator's representative, shall successfully complete a USGS-approved refresher course annually and repeat the basic well-control course every 4 years, as described in the provisions of GSS–OCS–T 1. Credit for these courses shalld be obtained from USGS-approved schools. The refresher course shall be completed within 45 days of the student's anniversary date. The anniversary date is established upon the student's successful completion of a basic course in well control.

Records shall be maintained at the drill site for the affected personnel, indicating the specific training and refresher courses successfully completed, the dates of completion, and the names and dates of the courses.

The lessee shall ensure that personnel responsible for maintenance of the blowout preventer stack, the associated-control equipment, and the hydraulic-control fluids shall be instructed in the proper procedures to prevent freezing of the hydraulic-control fluids in the control system and the fluids in the choke and kill lines.

8. *Hydrogen Sulfide.* When drilling operations are planned which will penetrate reservoirs known or expected to contain hydrogen sulfide (H_2S), or in those areas where the presence of H_2S is unknown, or upon encountering H_2S, the preventive measures and the operating practices set forth in USGS Outer Continential Shelf Standard "Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment," No. 1 (GSS–OCS–1), First Edition, February 1976, or subsequent revisions thereto, shall be followed.

9. *Critical Operations and Curtailment Plans.* Certain operations performed in drilling are more critical than others with respect to well control, and for the prevention of fire, explosion, oil spills, and other discharges or emissions. The lessee shall submit with the Exploration Plan or Development and Production Plan a Critical Operations and Curtailment Plan to be followed while conducting drilling operations on each lease. This plan shall include:

a. A list or description of the critical drilling operations that are, or are likely to be, conducted on the lease. This list or description shall specify the operations to be ceased, limited, or not to be commenced under given circumstances or conditions. This list shall include operations such as:

(1) Drilling in close proximity to another well.

(2) Drill-stem testing.

(3) Running and cementing casing.

(4) Cutting and recovering casing.

(5) Logging or wireline operations.

(6) Well-completion operations.

(7) Moving the drilling vessel off location in an emergency, repositioning the vessel on location, and reestablishing entry into the well.

b. A list or description of circumstances or conditions under which such critical operations shall be curtailed. This list or description shall be developed from all the factors and conditions relating to the conduct of operations on the lease, and shall

consider but not necessarily be limited to the following:

(1) Whether the drilling operations are to be conducted from mobile or fixed platforms.

(2) The availability and capability of containment and cleanup equipment and spill-control system response time.

(3) Abnormal or unusual conditions expected to be encountered during drilling operations.

(4) Known or anticipated meteorological, oceanographic, and ice conditions.

(5) Availability of personnel and equipment for particular operations to be conducted.

(6) Other factors peculiar to the particular lease under consideration.

c. The name of the person who has responsibility as the person-in-charge of overall drilling operations.

When any circumstance or condition listed or described in the plan occurs or other operational limits are encountered, the lessee shall notify the District Supervisor and shall curtail the critical operations as set forth under 9a.

Deviations from the plan shall require prior approval of the District Supervisor. If emergency action requires deviation from the plan, the District Supervisor shall be notified as soon as possible. The lessee shall review the plan at least annually. The lessee shall notify the District Supervisor of the results of this review. Any amendments or modifications of the plan are subject to the approval of the District Supervisor.

10. *Field Drilling Rules.* When sufficient geological and engineering information is obtained as a result of drilling operations, the lessee may make an application or the DCM, Offshore Field Operations, may require an application for the establishment of field drilling rules. After field drilling rules have been established by the DCM, Offshore Field Operations, development wells shall be drilled in accordance with these rules and the requirements of this Order which are not affected by such rules.

11. *Use of Best Available and Safest Technologies (BAST).* The lessee is encouraged to continue the development of safety-system technology. As research and product improvement results in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used and, if such technologies provide a significant cost effective incremental benefit to safety, health, or the environment, shall be required to be used if determined to be BAST.

Conformance to the standards, codes, and practices referenced in this Order will be considered to be the application of BAST. Specific equipment and procedures or systems not covered by standards, codes, or practices will be analyzed to determine if the failure of such would have a significant effect on safety, health, or the environment. If such are identified and until specific performance standards or developed or endorsed by the U.S. Geological Survey (USGS), the lessee shall submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale why one alternative technology was considered in place of another. This analysis shall include a discussion of the costs involved in the use of such technology and the incremental benefits gained.

12. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic OCS Order No. 3—Effective February 27, 1981

Plugging and Abandonment of Wells

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.15 and 250.92. The lessee shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations shall not be commenced prior to obtaining approval from the appropriate District Supervisor. Oral or telegraphic approvals shall be in accordance with 30 CFR 250.13.

1. *Application for Approval to Abandon a Well.* In accordance with 30 CFR 250.92, the lessee shall submit for approval a Form 9–331, Sundry Notices and Reports on Wells, containing the following information:

1.1 *Notice of Intention to Abandon a Well.* A detailed statement of the proposed work for abandonment of any well. For all wells, the statement shall describe the proposed work (including, by depths, the kind, location, and length of plugs) and plans for mudding, cementing, shooting, testing, and removing casing, and other pertinent information. The statement as to a productible well shall set forth the reasons for abandonment, the amount and date of last production, and complete data from the last well test.

1.2 *Subsequent Report of Abandonment.* A detailed report of the manner in which the abandonment or plugging work was accomplished including the nature and quantities of materials used in the plugging and the location and extent, by depths, of casing left in the well, and the volume of mud fluid used. If an attempt was made to cut and pull any casing string, a description of the methods used and results obtained must be included.

2. *Permanent Abandonment.*

2.1 *Isolation of Zones in Open Hole.* In uncased portions of wells, cement plugs shall be spaced to extend 30 meters (98 feet) below the bottom to 30 meters (98 feet) above the top of any oil, gas, and freshwater zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata or the surface. The placement of additional cement plugs to prevent the migration of formation fluids in the well bore may be required by the District Supervisor.

2.2 *Isolation of Open Hole.* Where there is open hole below the casing, a cement plug shall be placed in the deepest casing string in accordance with "a" or "b" below. In the event lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed in accordance with "c" below:

a. A cement plug set by the displacement method so as to extend a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the casing shoe.

b. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the casing shoe, with a cement plug calculated to extend at least 30 meters (98 feet) below the casing shoe and 15 meters (49 feet) above the retainer.

c. A permanent-type bridge plug set within 45 meters (148 feet) above the casing shoe with 15 meters (49 feet) of cement on top of the bridge plug. This bridge plug shall be tested in accordance with subparagraph 2.7 prior to placing subsequent plugs.

2.3 *Plugging or Isolating Perforated Intervals.* A cement plug shall be set by the displacement method opposite all open perforations (perforations not squeezed with cement) extending a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the perforated interval or down to a casing plug, whichever is less. In lieu of setting a cement plug by the displacement method, the following two methods are

acceptable, provided the perforations are isolated from the hole below:

a. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the top of the perforated interval with a cement plug calculated to extend at least 30 meters (98 feet) below the bottom of the perforated interval and 15 meters (49 feet) above the retainer.

b. A permanent-type bridge plug set within 45 meters (148 feet) above the top of the perforated interval with 15 meters (49 feet) of cement on top of the bridge plug.

2.4 *Plugging of Casing Stubs.* If casing is cut and recovered leaving a stub, one of the following methods shall be used to plug the casing stub:

2.4.1 *Stub Termination Inside Casing String.* A stub terminating inside a casing string shall be plugged by one of the following methods:

a. A cement plug set so as to extend 30 meters (98 feet) above and 30 meters (98 feet) below the stub.

b. A cement retainer set 15 meters (49 feet) above the stub with a volume of cement equivalent to 45 meters (148 feet) squeezed below the retainer and with an additional 15 meters (49 feet) placed above the retainer.

c. A permanent bridge plug set 15 meters (49 feet) above the stub and capped with 15 meters (49 feet) of cement.

2.4.2 *Stub Termination Below Casing String.* If the stub is below the next larger string, plugging shall be accomplished in accordance with either subparagraph 2.1 or 2.2.

2.5 *Plugging of Annular Space.* Any annular space communicating with any open hole and extending to the ocean floor shall be plugged with cement.

2.6 *Surface Plug.* A cement plug at least 45 meters (148 feet) in length, with the top of the plug 45 meters (148 feet) or less below the ocean floor, shall be placed in the smallest string of casing which extends to the ocean floor.

2.7 *Testing of Plugs.* The setting and location of the first plug below the surface plug shall be verified by one of the following methods:

a. by placing a minimum pipe weight of 6,800 kilograms (15,000 pounds) on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer need not be tested.

b. By testing the plug with a minmum pump pressure of 6,900 kPa (1,000 psi) with no more than a 10-percent pressure drop during a 15-minute period.

2.8 *Mud.* Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling the intervals between the plugs. Fluid left in the hole adjacent to the permafrost zone shall have a freezing point below the temperature of the permafrost zone and shall be treated to minimize corrosion of the casing. Any oil base fluid left in the hole will require prior approval of the District Supervisor.

2.9 *Clearance of Location.* All casing, wellhead equipment, and piling shall be removed to a depth of at least 5 meters (16 feet) below the ocean floor, or to a depth approved by the District Supervisor after a review of data on the ocean bottom conditions. The lessee shall verify that the location has been cleared of all obstructions.

2.10 *Cement.* The cement used for cement plugs placed across the permafrost zones shall be designed to set before freezing and to have a low heat of hydration.

3. *Temporary Abandonment.* Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for the requirements in subparagraphs 2.6 and 2.9. When a drilling well is temporarily abandoned, a bridge plug or a cement plug shall be set at the base of the deepest casing string. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole.

The lessee shall set a retrievable or permanent bridge plug, or a cement plug at least 30 meters (98 feet) in length in the casing between 5 and 60 meters (16 and 197 feet) below the ocean floor.

When a casing stub extends above the ocean floor, the lessee shall comply with the requirements of OCS Order No. 1, paragraph 4, "Identification of Subsea Objects."

4. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic OCS Order No. 4—Effective February 27, 1981

Determination of Well Producibility

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.12. An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production of oil and gas in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved in accordance with 30 CFR 250.12.

1. *Application for Determination of Well Producibility.* An application shall be submitted to the District Supervisor for the determination of every new well's capability of producing until a well, drilled on the lease, has been determined to be capable of producing oil or gas in paying quantities. The application shall be submitted within 60 days after the drilling rig has been moved from the well.

2. *Criteria for the determination of Well Producibility.* The Deputy Conservation Manager (DCM), Offshore Field Operations, shall prescribe which of the following criteria is to be used to determine the capability of a well to produce in paying quantities.

2.1 *Production Tests.* All tests must be witnessed by an authorized representative of the U.S. Geological Survey. Test data accompanied by the lessee's affidavit, or third-party test data, may be accepted in lieu of a witnessed test, provided approval is obtained from the District Supervisor prior to the performance of the test. All tests must conform to the following minimum requirements:

a. A production test for oil wells of a least 2 hours' duration following stabilization of flow.

b. A deliverability test for gas wells of at least 2 hours' duration following stabilization of flow or a 4-point back-pressure test.

2.2 *Production Capability Determination.* When the District Supervisor determines that open hole evaluation data, such as wireline formation test, drill stem tests, core data, and logs, have been demonstrated as reliable in a geologic area, such data may be considered as acceptable evidence that a well is capable of producing in paying quantities.

3. *Departures.* All departures from the requirements specified in this Order

shall be subject to approval, pursuant to 30 CFR 250.11(b)

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic OCS Order No. 5—Effective February 27, 1981

Production Safety Systems

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10 and 250.11 and in accordance with 30 CFR 250.30, 250.38, 250.45, and 250.46. The lessee shall be responsible for compliance with the requirements of this Order in the installation and operation of the production safety systems on all platforms and structures located on the leasehold including those facilities not operated or owned by the lessee. All applications for approval under the provisions of this Order shall be submitted to the District Supervisor.

This Order requires the lessee to submit plans, applications, reports, data, and other information. In all cases where the lessee(s) has(have) identified another party as designated lease operator in accordance with 30 CFR 250.31, and where the term "operator" is defined in accordance with 30 CFR 250.2(gg), the required information may be submitted by the designated lease operator.

1. *Use of Best Available and Safest Technologies (BAST).* The lessee is encouraged to continue the development of safety-system technology. As research and product improvement results in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used and, if such technologies provide a significant cost effective incremental benefit to safety, health, or the environment, shall be required to be used if determined to be BAST.

Conformance to the standards, codes, and practices referenced in this Order will be considered to be the application of BAST. Specific equipment and procedures or systems not covered by standards, codes, or practices will be analyzed to determine if the failure of such would have a significant effect on safety, health, or the environment If such are identified and until specific performance standards are developed or endorsed by the U.S. Geological Survey (USGS), the lessee shall submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale why one alternative technology was considered in place of another. This analysis shall include a discussion of the costs involved in the use of such technology and the incremental benefits gained.

1.1 *Subfreezing Operations.* Lessees shall furnish evidence that the production equipment, production safety systems, and other associated equipment and materials are suitable for operations under subfreezing conditions and that all equipment and operating procedures take into account floating ice, icing and other extreme environmental conditions that may occur in the area.

2. *Quality Assurance and Performance of Safety and Pollution-Prevention Equipment.* Safety and Pollution-Prevention Equipment (SPPE) shall conform to the following quality assurance standards:

a. American National Standards Institute/American Society of Mechanical Engineers Standard "Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME SPPE–1, latest edition with all addenda.

b. American National Standards Institute/American Society of Mechanical Engineers Standard "Accreditation of Testing Laboratories for Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME–SPPE–2, latest edition with all addenda.

The applicable SPPE components, and the applicable SPPE specifications are identified in subparagraph 3.2 and subparagraph 4.2.

3. *Subsurface-Safety Devices.*

3.1 *Installation.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-safety device such as a Surface-Controlled Subsurface-Safety Valve (SCSSV), a Subsurface-Controlled Subsurface-Safety Valve (SCSSV), an injection valve, a tubing plug, or a tubular/annular subsurface-safety device, unless, after application and justification, the well is determined to be incapable of flowing. Criteria and procedural guidelines for the determination of the capability of a well to flow are established by and are available from the District Supervisor. The device shall be installed within 2 days after production is stabilized. The well shall be attended in the immediate vicinity of the well so that emergency actions may be taken, if necessary, while the well is open to flow from a hydrocarbon-bearing zone, until a subsurface-safety device is installed.

In non-permafrost areas, the device shall be installed at a depth of 30 meters (98 feet) or more below the ocean floor. In permafrost areas, the setting depth of the subsurface-safety device shall be approved by the District Supervisor on a case-by-case basis.

3.1.1 *Subsurface-Safety Valves.* All tubing installations shall be equipped with a surface-controlled, or other remotely controlled, subsurface-safety device. Alternatives to this requirement may be approved by the Deputy Conservation Manager (DCM), Offshore Field Operations, when greater reliability or safety can be demonstrated.

3.2 *Specification for Subsurface-Safety Valves.* Surface-controlled and subsurface-controlled subsurface-safety valves required by subparagraphs 3.4 and 3.5, which are installed or replaced, shall conform to "American Petroleum Institute (API) Specification for Subsurface-Safety Valves," API Spec 14A, Fourth Edition, November 1979, with the exception of section 6, Appendix A and Appendix J of this specification, except for specific provisions thereof that are required in sections 1 through 5 of this specification, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use at the time of installation. The API monogram is optional, whereas the requirement for the OCS symbol is mandatory. A valve qualified to a previous edition of API Spec 14A is acceptable provided that the valve enters inventory within 3 years of its qualifying performance test date.

For purposes of this requirement, the term "replacement" is defined as occurring when that portion of the valve assembly containing the serial number is removed from inventory and a new certified valve is placed in inventory.

3.3 *Design, Installation, and Operation.* Subsurface-safety devices shall be designed , adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.

3.4 *Surface-Controlled Subsurface-Safety Valves.* All tubing installations open to a hydrocarbon-bearing zone shall be equipped with a surface-controlled subsurface-safety valve, except as specified in subparagraphs 3.1, 3.5, and 3.6. The surface controls

may be located on the site or at a remote location.

3.4.1 *Testing of Surface-Controlled Subsurface-Safety Valves.* Each surface-controlled, or other remotely controlled, subsurface-safety device installed in a well shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months. If the device does not operate properly, it shall be removed, repaired, reinstalled or replaced, and tested to insure proper operation.

3.5 *Subsurface-Controlled Subsurface-Safety Valves.* Tubing installations in wells completed from single-well or multiwell satellite caissons or ocean floor completions may be equipped with a subsurface-controlled subsurface-safety valve in lieu of a surface-controlled, or other remotely controlled, or other remotely controlled, subsurface-safety valve.

3.5.1 *Inspection and Maintenance of Subsurface-Controlled Subsurface-Safety Valves.* Each subsurface-controlled subsurface-safety valve installed in a well shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding:

(1) 6 months for those valves not installed in a landing nipple.

(2) 12 months for those valves installed in a landing nipple.

3.6 *Tubing Plugs in Shut-in Wells.* A tubing plug shall be installed in lieu of, or in addition to, other subsurface-safety devices if a well has been shut-in for a period of 6 months. In nonpermafrost areas, tubing plugs shall be set at a depth of 30 meters (98 feet) or more below the ocean floor. In permafrost areas, each tubing-plug installation shall be approved by the District Supervisor on a case-by-case basis. All tubing plugs installed shall be of the pump-through type. All wells perforated anc completed but not placed on production shall be equipped with a subsurface-safety valve or tubing plug within 2 days after completion. A surface-controlled subsurface-safety valve of the pump-through type may be used as a pump-through tubing plug for the purpose of this subparagraph, provided the surface control has been rendered inoperative. A shut-in well which is equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 400 cc/min or a gas leakage rate in excess of 7 dm^3 / sec (15 cubic ft/min) is observed, the plug shall be removed, repaired, and reinstalled, or an additional tubing plug may be installed in lieu of removal and repair.

3.7 *Injection Wells.* A surface-controlled subsurface-safety valve or an injection valve capable of preventing backflow shall be installed in all wells placed in injection service.

Surface-controlled subsurface-safety valves shall be tested in accordance with subparagraph 3.4.1. Injection valves shall be tested in the manner as outlined for testing tubing plugs in subparagraph 3.6.

These requirements are not applicable if the District Supervisor concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually and submit an annual report certifying the no-flow status of the well.

3.8 *Temporary Removal for Routine Operations.* Each wireline- or pumpdown-retrievable subsurface-safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Sundry Notice and Report on Wells (Form 9–331) for a period not to exceed 15 days. The well shall be identified by a sign on the wellhead stating that the subsurface-safety device has been removed. The removal of the subsurface-safety device shall be noted in the records as required by subparagraph 3.11g. The well shall be attended in the immediate vicinity of the well so that emergency actions may be taken, if necessary, while the well is open to flow from a hydrocarbon-bearing zone until the subsurface-safety device is reinstalled, unless attendance has been waived by the District Supervisor. The well shall not be open to flow while the subsurface-safety device is removed except when flowing the well is necessary for that particular operation.

The provisions of this paragraph are not applicable to the testing and inspection procedures in subparagraphs 3.4.1, 3.5.1, 3.6, and 3.7.

3.9 *Additional Safety Equipment.* All tubing installations in which a wireline- or pumpdown-retrievable subsurface-safety device is installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for the setting of the subsurface-safety valve. The control system for all surface-controlled subsurface-safety valves shall be an integral part of the platform Emergency Shutdown System (ESD) as defined in Appendix C, Section C1 of "API Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface-Safety Systems on Offshore Production Platforms," API RP 14C, Second Edition, January 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. In addition to the activation of the ESD system by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled subsurface-safety valves shall close in response to shut-in signals from the ESD system or the fire loop, or both.

3.10 *Emergency Action.* All tubing installations open to hydrocarbon-bearing zones and capable of flowing in which the subsurface-safety device has been removed, in accordance with the provisions of this Order, shall be identified by a sign on the wellhead stating that the subsurface-safety device has been removed. A subsurface-safety device shall be available for each well on the platform. In the event of an emergency such as an impending storm, this device shall be properly installed as soon as possible with due consideration being given to personnel safety.

3.11 *Records.* The lessee shall maintain records for a minimum period of 5 years for each subsurface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office. The records may than be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the USGS. The records to be maintained shall contain verification of:

a. The manufacturer's design, including make, model, and type. For subsurface-controlled valves, number of the spacers, size of beams, springs, and the pressure settings.

b. The devices having been manufactured in accordance with the quality-assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as required by paragraph 2.

c. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SPPE–1.

d. The record of all configuration modifications to the certified design.

e. Installation at the required setting depth and in accordance with the manufacturer's instructions.

f. The identity of the personnel qualified in accordance with subparagraph 5.7 who directed all installations and removals.

g. The results of tests required by this Order, the dates of removals and reinstallations, and the reasons for removals and reinstallations.

h. The completion and submission of all failure reports required by paragraph

6 and all investigation reports required by paragraphs OE–2529 and OE–2670 of ANSI/ASME–SPPE–1.

3.12 *Reports.* Well completion reports (Form 9–330) and any subsequent reports of workover (Form 9–331) shall include the manufacturer, the type, and the installed depth of the subsurface-safety devices.

4. *Design, Installation, and Operation of Surface Production Safety Systems.* All production facilities, including separators, treaters, compressors, headers, and flowlines, shall be designed, installed, and maintained in a manner which will facilitate an efficient, safe, and pollution-free operation.

4.1 *New Platforms.* New platform production facilities shall be protected with a basic and ancillary surface-safety system designed, analyzed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C, except Section A9, "Pipelines," which will be covered under OCS Order No. 9, and the additional requirements of Order No. 5. For this application, the work "should" contained in API RP 14C shall be read "shall," except for those contained in explanatory statements, sections 3.4c and 4.3a(4)(a)-(f). If processing component are to be utilized, other than those for which Safety Analysis Checklists (SAC's) are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of these components upon the safety system.

4.2 *Specification for Wellhead Surface-Safety Valves.* All Wellhead Surface-Safety Valves (SSV's) required by subparagraph 4.1 shall conform to "API Specification for Wellhead Surface Safety Valves for Offshore Service," API Spec 14D, Third Edition, November 1980, with the exception of Appendix A and Appendix J of this specification, except for specific provisions thereof that are required in sections 1 through 5 of this specification, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use at the time of installation. The API monogram is optional, whereas the requirement for the OCS symbol is mandatory.

4.3 *Submittal of Safety-System Design and Installation Features.* Prior to installation, the lessee shall submit for approval to the District Supervisor, in duplicate, information relative to design and installation features, as indicated in subparagraphs "a" through "g." This information shall also be maintained at the lessee's onshore field engineering office. All approvals are subject to field verifications. This information shall include:

a. A schematic flow diagram showing size, capacity, and design working pressure of separators, treaters, storage tanks, compressors, pipeline pumps, and metering devices.

b. A schematic flow diagram (reference API RP 14C, example: figure E1) and the related Safety Analysis Function Evaluation (SAFE) chart (reference API RP 14C, Subsection 4.3c). These diagrams and charts shall be developed in accordance with the provisions of API RP 14C and the additional requirements of this Order.

c. A schematic piping diagram showing the size and maximum-allowable working pressure with reference to welding specification(s) or code(s) used. The maximum-allowable working pressures shall be determined in accordance with "API Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems," API RP 14E, First Edition, August 1975, and Supplement 2, October 1977, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. The recommendations contained in API RP 14E are acceptable for the design and installation of the platform piping system.

d. A diagram of the firefighting system.

e. Electrical system information including the following:

(1) A plan of each platform deck outlining any nonrestricted area, i.e., areas which are unclassified with respect to electrical equipment installations and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outline shall include the following information:

(a) Any surrounding production or other hydrocarbon source and a description of the deck, overhead, and firewall.

(b) Location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the wiring method, including the identification of each wire and cable type that is utilized.

(2) Elementary electrical schematic of any platform safety-shutdown system with a functional legend.

(3) Classification of areas for electrical installations in accordance with the National Electrical Code, 1978 Edition, and with the "API Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Lands and on Marine Fixed and Mobile Platforms," API RP 500B, Second Edition, July 1973, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

f. The design and schematics of the installation and maintenance of all fire and gas detection systems shall include the following:

(1) Type, location, and number of detection heads.

(2) Type and kind of alarm, including emergency equipment to be activated.

(3) Method used for detection.

(4) Method and frequency of calibration.

(5) Name of organization to perform system inspection and calibration.

(6) A functional block diagram of the detection system, including the electric power supply.

g. Certification that the design for the mechanical and electrical systems to be installed was approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that the new installations conform to the approved designs or the lessee shall request approval of the "As-Built" changes.

5. *Additional Safety and Pollution-Control Requirements.* The following requirements modify or are in addition to those contained in API RP 14C.

5.1 *Design, Installation, and Operation.*

5.1.1 *Pressure Vessels.* Unless otherwise qualified for use according to subparagraph 5.1.1d below, pressure vessels shall be designed, fabricated, stamped, and maintained in accordance with specific sections of the ASME Boiler and Pressure Vessel Code as listed below. The pressure vessels shall conform to the July 1, 1977, edition of the Code or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

a. Pressure-relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

b. Steam generators shall be equipped with Level Safety Low Controls (LSL) in accordance with applicable provisions of sections I and IV.

c. The lessee shall determine, by the use of pressure recorders, the operating pressure ranges of all pressure-operated vessels in order to establish the

pressure-sensor settings. Current pressure-recorder charts shall be maintained at the nearest offshore field office. The high-pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the vessel. This setting shall also be sufficiently below the relief valve's set pressure to assure that the pressure source is shut in before the relief valve starts relieving. The low-pressure shut-in pressure-sensor setting shall be no lower than 15 percent or 35 kilopascals (kPa) (5 psi), whichever is greater, below the lowest pressure in the operating range. The pressure-sensor setting of low-pressure sensors on pressure vessels which operate at less than 35 kilopascals (kPa) (5 psi) shall be approved by the District Supervisor on a case-by-case basis.

d. All pressure or fired vessels used in the production of oil or gas shall conform to the requirements stipulated in the edition of the ASME Boiler and Pressure Vessel Code, sections I, IV, and VIII, as appropriate, in effect at the time the vessel is ordered. Uncoded vessels shall the hydrostatically tested to a pressure 1.5 times their working pressures prior to placing in service. The test date, test pressure, and working pressure shall be marked in the vessel in a prominent place. A record of the test shall be maintained by the lessee in the field area.

5.1.2 *Flowlines.*

a. All flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located in accordance with Section A1 and Figure A1 of API RP 14 C. The lessee shall determine, by the use of pressure recorders, the operating pressure ranges of flowlines in order to establish pressure-sensor settings. Current pressure-recorder charts shall be maintained at the nearest offshore field office.

The high-pressure shut-in sensor(s) shall be set no higher than 10 percent above the highest operating pressure of the line; but, in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the surface-safety valve. The low-pressure shut-in sensor(s) shall be set no lower than 10 percent or 35 kPa (5 psi), whichever is greater, below the lowest operating pressure of the line in which it is installed.

b. If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of, and including the header inlet valve(s), shall have a working pressure equal to or greater than the maximum shut-in pressure of the well, unless the flowline is protected by one of the following:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Supervisor.

(2) An additional automatic shutdown valve controlled by an independent high/pressure sensor. The platform flare scrubber shall be designed to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid-hydrocarbons which may be relieved to the vessel.

5.1.3 *Pressure Sensors.* Pressure sensors may be of the automatic- or nonautomatic-reset type. When the automatic-reset types are used, a nonautomatic-reset relay shall be installed. All pressure sensors shall be equipped to permit testing with an external pressure source.

5.1.4 *Emergency Shutdown System.* The manually operated ESD valve shall be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. ESD stations may utilize a loop of breakable synthetic tubing in lieu of a valve only at the boat landing.

On an emergency shutdown, the Surface-Controlled Subsurface-Safety Valve (SCSSV) shall close in not more than 2 minutes after the shut-in signal has closed the surface safety valve (SSV). Design delayed closure time greater than 2 minutes shall be justified by the lessee based on the individual well's mechanical/production characteristics and approved by the District Supervisor.

Electro-pneumatic systems shall meet the corresponding design and functional requirements as those which apply to pneumatic systems.

A schematic of the ESD system which indicates the control functions of all safety devices shall be maintained on the platform or nearest offshore field office.

5.1.5 *Engine Exhausts.* Engine exhausts shall be equipped to comply with the insulation and personnel-protection requirements of API RP 14C, Section 4.2c(4). Exhaust piping from diesel engines shall be equipped with spark arrestors.

5.1.6 *Glycol-Dehydration Units.* A pressure-relief system or an adequate vent shall be installed on the glycol regenerator, or at a location approved by the District Supervisor, which will prevent overpressurization of all glycol-dehydration units. The set pressure of the pressure-relief system shall be determined by the lessee and approved by the District Supervisor. The discharge of the relief valve shall be vented in a nonhazardous manner. The glycol-dehydration unit shall be properly maintained to prevent overpressurization of the unit.

5.1.7 *Gas Compressors.* Each compressor shall be equipped with the following protective equipment:

(1) A PSH, a PSL, a PSV, and an LSH to protect each interstage and suction scrubber.

(2) An LSL to protect each interstage and suction scrubber, unless the fluid is dumped through a choke restriction to another pressure vessel. An LSL shut-in control(s) installed in interstage and suction scrubber(s) may be designed to actuate the automatic shutdown valve(s) (SDV's) installed in the scrubber dump line(s).

(3) A TSH on each compressor cylinder or other components as applicable.

(4) In addition to the provisions of API RP 14C, Subsection A8.3, PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designed to actuate automatic SDV's located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources.

All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover.

Compressor installations of 745 kilowatts (1,000 horsepower) or less are excluded from those requirements of API RP 14C, A8.3d, which provide for installation of a blowdown valve (BDV) on the discharge line.

5.1.8 *Firefighting Systems.* Firefighting systems shall conform to Subsection 5.2, "Fire Water Systems," of "API Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms," API RP 14G, First Edition, September 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use, and the additional requirements of this subparagraph.

A firewater system consisting of rigid pipe with firehose stations shall be installed. The firewater system shall be installed to provide needed protection in all areas where production-handling equipment is located. A fixed water-spray system shall be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate.

Acceptable pump drivers include diesel engines, natural gas engines, and electric motors. Fuel or power shall be available for at least 30 minutes of run-time during platform shut-in time. If necessary, an alternate fuel supply shall be installed to provide for this pump-

operating time unless an alternate firefighting system has been approved by the District Supervisor.

A firefighting system using chemicals may be used or may be required in lieu of a water system if the District Supervisor determines that the use of a chemical system provides equivalent fire protection control. A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the platform or structure.

5.1.9 *Fire and Gas Detection System.*

a. Fire (flame, heat, or smoke) sensors shall be used in all enclosed high-hazard areas. Gas sensors shall be used in all inadequately ventilated, enclosed, high-hazard areas. Adequate ventilation is as defined in API RP 14C, Appendix C, paragraph C1.3b.

b. All detection systems shall be capable of continuous monitoring. Fire detection systems and portions of combustible gas detection systems related to the higher gas concentration levels shall be of the manual-reset type. Combustible gas detection systems related to the lower gas concentration level may be of the automatic-reset type.

c. A fuel gas odorant or an automatic gas-detection and alarm system are required in enclosed, continuously manned areas of the facility.

d. The District Supervisor may require a gas detector or alarm in any potentially hazardous area.

e. Fire detection systems shall be of an approved type, designed and installed in accordance with the National Fire Protection Association Standard for Automatic Fire Detectors, No. 72E, 1974, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Gas detection systems shall be of an approved type, designed and installed in accordance with sections 9.1 and 9.2 of "API Recommended Practice For Design and Installation of Electrical Systems for Offshore Production Platforms," API RP 14F, First Edition, July 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

5.1.10 *Electrical Equipment.* The following requirements shall be applicable to all electrical equipment and systems:

a. All engines with ignition systems shall be equipped with a low-tension ignition system of a low-fire hazard type and shall be designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture.

b. All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500B in effect at the time of approval.

c. At the time of approval, wiring methods shall conform to the National Electrical Code, 1978 Edition, or to the Institute of Electrical and Electronic Engineers (IEEE) "Recommended Practice for Electric Installation on Shipboard," IEEE Std. 45–1977, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Each conductor of a wire, a cable, or a bus bar shall be made of copper on all installations.

d. The elementary electrical schematic of the platform safety-shutdown system required by subparagraph 4.3e(2) shall be maintained on the platform or structure. This schematic shall indicate the control functions of all electrically actuated safety devices.

e. Maintenance of these systems shall be by personnel who are familiar with the construction and operation of the equipment and the hazards involved.

f. An auxiliary power supply shall be installed to provide emergency power, capable of operating all electrical equipment required to maintain safety of operations, in the event of a failure in the primary electrical power supply. This requirement is not applicable to those systems, or portions of systems, which are designed to fail-safe.

5.1.11 *Erosion.* A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. An annual report, by lease, indicating the wells which have erosion-control programs in effect and the results of the programs shall be submitted by the first of December to the USGS Conservation Manager in the appropriate Regional Office.

5.2 *General Platform Operations.*

a. Surface- or subsurface-safety devices shall not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices necessary for the operation shall be taken out of service. Personnel shall monitor the bypassed or blocked-out functions. Any surface- or subsurface-safety device which is temporarily out of service shall be flagged.

b. When wells are disconnected from producing facilities and blind-flanged or equipped with a tubing plug, compliance is not required with the provisions of API RP 14C or this Order concerning:

(1) Installation of automatic fail-close SSV on wellhead assemblies.

(2) Installation of the PSH and the PSL shut-in sensors downstream of the choke in flowlines from wells.

(3) Installation of flow safety valves (FSV's) in header individual flowlines.

c. When pressure or atmospheric vessels are positively isolated from production facilities (for example, inlet valve locked closed or inlet line blind-flanged) and are to remain isolated for an extended period of time, safety device compliance is not required with API RP 14C or this Order.

d. All open-ended lines connected to producing facilities shall be plugged or blind-flanged, except those lines designed to be open-ended, such as flare or vent lines.

5.3 *Simultaneous Platform Operations.* Prior to conducting activities simultaneously with production operations which could increase the possibility of occurrence of undesirable events, such as harm to personnel or to the environment or damage to equipment, a "General Plan for Conducting Simultaneous Operations" in a producing field shall be filed for approval with the District Supervisor. This plan shall be modified and updated by supplemental plans when actual simultaneous operations are scheduled which are significantly different from those covered in the General Plan. Activities requiring these plans are drilling, completion, workover, wireline, pumpdown, and major construction operations.

5.3.1 *General Plan.* The "General Plan for Conducting Simultaneous Operations" shall include:

a. A narrative description of operations.

b. Procedures for the mitigation of potentially undesirable events including:

(1) The guidelines the lessee will follow to assure coordination and control of simultaneous activities.

(2) The identity of the person having overall responsibility at the site for the safety of platform operations.

5.3.2 *Supplemental Plan.* The "Supplemental Plan for Conducting Simultaneous Operations" shall include:

a. A floor plan of each platform deck indicating critical areas of simultaneous activities.

b. An outline of any additional safety measures that are required for simultaneous operations.

c. Specification of any added or special equipment or procedural conditions imposed when simultaneous activities are in progress.

5.4 *Welding and Burning Practices and Procedures.* The following requirements are applicable to any welding or burning practice or procedure performed on:

a. An offshore mobile-drilling unit during the drilling mode.

b. A mobile workover unit during any drilling, completion, recompletion, remedial, repair, stimulation, or other workover activity.

c. A platform, structure, artificial island, or other installation during any drilling, completion, workover, or production operation.

d. A platform, structure, artificial island, or other installation which contains a well open to a hydrocarbon-bearing zone.

For the purpose of this Order, the terms "welding" and "burning" are defined to include arc or acetylene cutting and arc or acetylene welding.

All offshore welding and burning shall be minimized by onshore fabrication when feasible.

5.4.1 *General Welding, Burning, and Hot Tapping Plan.* Each lessee shall file for approval by the District Supervisor a "Welding, Burning, and Hot Tapping Safe Practices and Procedures Plan." The plan shall include the qualification standards or requirements for personnel and the methods by which the lessee will assure that only personnel meeting such standards or requirements are utilized. A copy of this plan shall be available in the field area. Any person designated as a welding supervisor shall be thoroughly familiar with this plan. An approved plan is required prior to the conduct of any welding, burning or hot tapping operation. All welding and burning equipment shall be inspected prior to beginning any welding or burning. Welding machines located on production or process platforms shall be equipped with spark arrestors and drip pans. Welding leads shall be completely insulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak-free and equipped with proper fittings, gauges, and regulators.

5.4.2 *Designated Safe-Welding and Burning Areas.* The lessee shall establish, if feasible, and so designate areas on the platform determined to be safe-welding areas pursuant to the National Fire Protection Association Bulletin "Cutting and Welding Processes," No. 51 B, 1976, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Approval for the use of such areas shall be obtained from the District Supervisor. These designated areas shall be identified in the General Plan and a drawing showing the location of these areas shall be maintained on the facility. Welding or burning performed in any other areas shall be performed in compliance with the procedures set forth in subparagraph 5.4.3.

5.4.3 *Undesignated Welding and Burning Areas.* All welding or burning which cannot be done in an approved safe-welding area shall be performed in compliance with the procedures outlined below:

a. Prior to the commencement of any welding or burning operation on a structure, the lessee's designated person-in-charge at the installation shall personally inspect the qualifications of the welder or welders to assure that they are properly qualified in accordance with the lessee-approved qualification standards or requirements for welders. The designated person-in-charge and the welders shall personally inspect the work area for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the designated person-in-charge shall issue a written authorization for the work.

b. During all welding and burning operations, one or more persons shall be designated as a Fire Watch. Persons assigned as a Fire Watch shall have no other duties while actual welding or burning operations are in progress. If welding is to be done in an area which is not equipped with a gas detector, the Fire Watch shall also maintain a continuous surveillance with a portable gas detector during welding.

c. Prior to any welding or burning operation, the Fire Watch shall have in his possession firefighting equipment in a usable condition. At the end of the welding operation, the equipment shall be returned to a usable condition.

d. No welding, other than approved hot tapping, shall be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered inert and determined to be safe for welding or burning by the designated person-in-charge.

e. If drilling, workover, or wireline operations are in progress on the platform, welding operations in other than approved safe-welding areas shall not be conducted unless the well(s) where these operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded. All other provisions of this section shall also be applicable.

f. If welding or burning operations are conducted in the well-bay or production area, all producing wells shall be shut in at the surface-safety valve.

5.5 *Safety Device Testing.* The safety-system devices which are required by this Order shall be tested by the lessee at the interval specified below or more frequently if operating conditions warrant. Testing shall be in accordance with API RP 14C, appendix D, and the following:

a. All PSV's shall be tested for operation at least once every 12 months. These valves shall be either bench-tested or equipped to permit testing with an external pressure source.

b. All Pressure Sensors-High/Low (PSHL) shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

c. All SSV's shall be tested for operation and for leakage at least once each calendar month, but at not time shall more than 6 weeks elapse between tests. The SSV's shall be tested for operation in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection L, and tested for leakage in accordance with subsection M. If the valve does not operate properly or any fluid flow is observed in step 3 of the leakage test, the valve shall be repaired or replaced.

d. All flowline FSV's shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's shall be tested for leakage in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection D. If the leakage measured in step 6 exceeds a liquid flow of 400 cc/min or a gas flow of 7 dm^3/sec (15 cubic ft/min), the FSV's shall be repaired or replaced.

e. All LSH and LSL controls shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. These tests shall be conducted by raising and lowering the liquid level across the level-control detector.

f. All automatic inlet SDV's which are actuated by a sensor on a vessel or a compressor shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

g. All SDV's located in liquid-discharge lines and actuated by vessel low-level sensors shall be tested for operation once each calendar month, but at no time shall more than 6 weeks elaspse between tests.

h. The TSH shutdown controls installed on compressors in lieu of a PSH and PSL on interstage scrubbers shall be tested every 6 months and repaired or replaced as necessary.

i. All pumps for firewater systems shall be inspected and test-operated weekly.

j. All fire (flame, heat, or smoke) and gas detection systems shall be tested for operation and recalibrated every 3 months.

k. The lessee shall notify the District Supervisor when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Supervisor upon commencement of production in order that a post-production test and inspection of the integrated system may be conducted.

l. All TSH devices on fired components shall be tested at least once every 12 months.

m. The ESD system shall be tested for operation at least once each calendar month but at not time shall more than 6 weeks elapse between tests. The test may be conducted by closing at least one SSV from each of the ESD stations.

5.6 *Records.* The lessee shall maintain records for a minimum period of 5 years for each surface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the USGS. The records shall show the present status and history of each device, including dates and details of installation, inspection, testing, repairing, adjustments, and reinstallation.

5.6.1 *Surface-Safety Valve and Assoicted Actuator Records.* Records for surface-safety valves and associated actuators which require compliance with paragraph 2 shall contain additional information showing vertification of:

a. The devices having been manufactured in accordance with the quality assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as required by paragraph 2.

b. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SPPE–1.

c. The completion and submission of all failure reports required by paragraph 6 and all investigation reports required by paragraphs OE–2529 and OE–2670 of ANSI/ASME–SPPE–1.

5.7 *Safety Device Training.* Before January 1, 1982, the lessee shall ensure that all personnel engaged in installing, inspecting, testing, and maintaining these safety devices will have been qualified under a program as recommended by "API Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work With Anti-Pollution Safety Devices," API RP T–2, revised October 1975, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

Documented evidence of the qualifications of individuals performing these functions shall be maintained in the field area.

Manufacturers' representatives need not be qualified in accordance with API RP T–2 if they are working on equipment supplied by their company, provided they have received training and are qualified by the manufacturer to install, service, or repair the specific safety device or safety system, and if they are directly supervised by an API RP T–2 qualified person who is cable of evaluating the impact of the work on the total system.

On-the-job trainees working with safety devices shall be directly supervised by a qualified person.

Before January 1, 1981, the lessee shall submit an application for approval to the Deputy Chief, Conservation Division—Offshore Minerals Regulation, describing the training to be conducted and the methods the lessee will utilize.

The application shall include:

a. A designation of the lessee's representative who is responsible for training and coordinating training matters with the USGS.

b. The categories of personnel to be qualified.

c. The training organizations and courses to be utilized.

d. The method for ensuring the qualification of third-party personnel.

e. The method for determining when additional training or requalification is required and the method for obtaining this training and requalification.

f. The method of monitoring operations to ensure that only qualified personnel perform certain functions.

g. The method of maintaining documented evidence of qualification at the work site.

6. *Failure and Inventory Reporting System (FIRS).* The USGS has established a safety and pollution-prevention device Failure and Inventory Reporting System (FIRS), to enhance the reliability and safety of operations in the OCS. This system applies to offshore structures, including satellites and jackets, which produce or process hydrocarbons and includes the attendant portions of hydrocarbon pipelines, when physically located on the structure.

When the devices specified herein are used as a part of the production safety and pollution-prevention system, the lessee shall:

a. Submit an initial inventory and periodic updates in accordance with the procedures described in subparagraph 6.1.3.

b. Report all device failures which occur. The report content and format shall be in accordance with the procedures described in subparagraph 6.1.4.

6.1 *Data and Reporting Requirements.*

6.1.1 *Format.* Inventory and failure data shall be submitted in a format containing the same information that is in the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report (Form 9–1995), and as outlined in the respective User's Instruction Booklets. Copies of the forms and booklets may be obtained from the USGS Conservation Manager in the appropriate Regional Office.

The specific method of submitting the required data may be selected from the following:

a. USGS Forms 9–1994 and 9–1995, using a standard coding convention (e.g., all letters capitalized, Z, I, letter O, number 0). The lessee shall submit the originals of the form to the USGS and retain the two copies.

b. ADP card decks of standard 80-column cards.

c. Magnetic tapes which are 9-track, 800 BPI, unlabeled, blocking cannot exceed, 1,040 characters, odd parity, single gap (i.e., compatible with IBM equipment EBCDIC).

Regardless of which method is used for submitting the inventory and failure data, a cover letter forwarding the data to the USGS shall contain the signature of the person initiating/approving the information contained therein.

When Form 9–1995 is used, the form shall contain in the lower right corner a signature of the person initiating/approving the report.

6.1.2 *Device Coverage.* Inventory and failure reports are to be submitted on the safety and pollution-prevention devices on offshore structures, including satellites and jackets, which produce or process hydrocarbons, and the hydrocarbon pipelines thereon. These reports shall be submitted on the following devices:

a. Blowdown Valves (BDV)
b. Burner Flame Detectors (BSL)
c. Check Valves (FSV)
d. Combustible Gas Detectors (ASH)
e. Emergency Shutdown Valves (ESD)

f. Level Sensors:
High (LSH)
Low (LSL)
Hi/Lo (LSHL)
g. Pressure Sensors:
High (PSH)
Low (PSL)
Hi/Lo (PSHL)
h. Relief Valves (PSV)
i. Shutdown Valves (SDV)
j. Subsurface-Safety Valves (SSSV)
k. Surface-Safety Valves (SSV)
l. Temperature Sensors:
High (TSH)
Low (TSL)
Hi/Lo (TSHL)
m. Valve Actuators on shutdown valves, blowdown valves, and surface-safety valves (VA)

6.1.3 *Device Inventory Reporting.*

6.1.3.1 *Initial Inventory.* A complete initial inventory of the active safety and pollution-prevention devices shall be submitted no later than 1 month after the initial platform production date.

6.1.3.2 *Inventory Updates.* An updating of or addition/deletion to the latest inventory shall be submitted on a monthly basis so as to maintain a current and accurate data base. The inventory will be updated by using the contents of the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report (Form 9–1995), as described in the FIRS Instruction Booklet.

Inventory updating due to the addition, deletion, or changeout of a device is accomplished *by the lessee* reporting all of the data required in the Safety Device Inventory Report (Form 9–1994). Whenever a device fails and is either replaced with a new device or "fixed" and put back into service, the inventory shall be updated to reflect this change. Inventory updating, due to the failure of a device, will be performed *by the USGS,* using the contents of the Safety Device Failure Report (Form 9–1995). Inventory updating information shall be received no later than 30 days following the month in which the device change was made.

6.1.3.3 *Inventory-Reporting Methods.* Inventory data shall be reported either on the Safety Device Inventory Reporting forms (Forms 9–1994), punched cards, or magnetic tapes. The reports shall contain all of the required information in the standard format as described in subparagraph 6.1.1.

6.1.3.4 *Inventory Verification.* The device inventory shall be verified by the lessee to ensure that the inventory data base is maintained on a current basis and that changes are being incorporated as they occur. The verification shall be accomplished no more frequently than once each 6-month period. When verification is required, the USGS will provide the lessee with a copy of the information on record, in the lessee's selected reporting format. The lessee shall review the information and either submit a letter stating that the information is correct, or make the appropriate corrections to the information provided by the USGS. The letter or appropriate corrections shall be received no later than 30 days following the month in which the inventory information which is to be verified was forwarded to the lessee.

6.1.3.5 *Inventory-Reporting Deviation.* A lessee may submit an inventory, update, or verification report differing from that described in subparagraph 6.1.3 when authorized by the USGS.

6.1.4 *Device Failure Reporting.*

6.1.4.1 *Failure-Data Submittal.* The failure data, as defined in subparagraph 6.1.4.3, shall be received no later than 30 days following the month in which the failure was detected. These data must contain all of the required information and be submitted in the standard format either on Safety Device Failure Report forms (Form 9–1995), punched cards, or magnetic tape, as previously described in subparagraph 6.1.1. Information on the failed device must match that previously submitted in inventory reporting. A formal failure analysis is not required by this Order, but each failed device shall undergo sufficient test/disassembly to establish the basic cause(s) of the failure.

6.1.4.2 *Failure-Data Verification.* After receipt of the complete failure data from the lessees, the USGS will make a printout of all failures by manufacturer, model, and reported cause. Each manufacturer listed will be furnished a copy of the printout containing the reported failures of his devices only. If he disagrees with the reported failure causes, he is invited to investigate the questioned causes in coordination with the reporting lessee and provide a coordinated reply within 6 weeks after receipt of the printout. If no reply is received within that time period, the originally reported causes will be considered to be correct, and the data will be evaluated accordingly.

6.1.4.3 *Failure Definition.* The safety and pollution-prevention device Failure and Inventory Reporting System does not differentiate between a malfunction and a failure. For the purpose of this program, a failure is defined as the inability of a device to perform its designed function within specified limits. A device is considered to have failed if it does not operate properly (perform its function) as required within the specified test tolerances. Examples of device failures are included in the FIRS Instruction Booklet.

A failure repot is not required for:

a. Adjustments made within specified tolerances.

b. Adjustments required due to changes in operating conditions.

6.2 *Records.* The lessee shall maintain FIRS data records for a minimum period of 5 years. Equipment failure records shall be maintained in the nearest offshore field office for a minimum period of 2 years. If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. The records shall be available for review by any authorized representative of the USGS.

7. *Crane Operations.* Cranes shall be operated and maintained to ensure the safety of facility operations in accordance with the provisions of "API Recommended Practice for Operation and Maintenance of Offshore Cranes," API RP 2D, October 1972, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Records of inspection, testing, maintenance, and crane operators qualified in accordance with the provisions of API RP 2D shall be kept in the field area for a period of 2 years. "API Specification for Offshore Cranes," API Specification 2C, February 1972, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use shall be used as a guideline for the selection of cranes.

8. *Employee Orientation and Motivation Programs for Personnel Working Offshore.* The lessee shall make a planned, continuing effort to eliminate accidents due to human error. This effort shall include the training of personnel in their functions. A program to achieve safe and pollution-free operations shall be established. This program shall include instructions in the provision of "API Recommended Practice Orientation Program for Personnel Going Offshore for the First Time," API RP T–1, January 1974, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. "API Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations," API Bulletin T–5, September 1974, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use shall be used as a guide in

developing employee safety and pollution-prevention motivation programs.

9. *Requirements for Drilling Rigs.*

9.1 *Fixed Structures.* The following requirements contained in this Order are applicable to drilling rigs on fixed structures:

a. Subparagraph 5.1.10, "Electrical Equipment."

b. Subparagraph 5.4, "Welding Practices and Procedures."

c. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

9.2 *Mobile Drilling Units.* The following requirements contained in this Order are applicable to drilling rigs on mobile drilling units:

a. Subparagraph 5.4, "Welding Practices and Procedures."

b. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

10. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic OCS Order No. 7—Effective February 27, 1981

Pollution Prevention and Control

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.43. The lessee shall comply with the following requirements:

1. *Pollution Prevention.* During the exploration, development, production, and transportation of oil and gas, the lessee shall prevent pollution of the ocean. Furthermore, by the disposal of waste materials into the ocean, the lessee shall not create conditions which will adversely affect the public health, life, property, aquatic life, wildlife, recreation, navigation, fishing, or other uses of the ocean.

1.1 *Liquid Disposal.*

1.1.1 *Drilling-Mud Components.* The lessee shall submit, as a part of the Application for Permit to Drill (Form 9-331 C), a detailed list of drilling-mud components including the common chemical or chemical trade name of each component, a list of the drilling-mud additives anticipated for use in meeting special drilling requirements, and the proposed method of drilling-mud disposal. The disposal of drilling mud is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of drilling-mud disposal into the ocean shall be obtained from the District Supervisor; each request will be decided on a case-by-case basis.

1.1.2 *Hydrocarbon-Handling Equipment.* All hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters shall be designed and operated to prevent pollution. Maintenance or repairs which are necessary to prevent pollution of the ocean shall be undertaken immediately.

1.1.3 *Curbs, Gutters, and Drains.*

1.1.3.1 *Fixed Platforms, and Structure.* Curbs, gutters, drip pans, and drains shall be installed in all deck areas in a manner necessary to collect all contaminants and piped to a properly designed, operated, and maintained sump system which will automatically maintain the oil at a level sufficient to prevent discharge of oil into OCS waters. Sump piles shall not be used as processing devices to treat or skim liquids, but shall be used to collect treated produced water, treated sand, liquids from drip pans and deck drains, and as a final trap for hydrocarbon liquids in event of equipment upsets.

1.1.3.2 *Artifical Islands.* On artificial islands, all vessels containing hydrocarbons shall be placed inside a berm lined with an imprevious material. The volume enclosed by the berm shall be in excess of the volume of vessels containing hydrocarbons. In addition, all drainage ditches shall be directed away from the drilling rig to a sump. The rig mat, the drainage ditches, and sumps shall be lined with impervious material.

1.1.3.3 *Mobile Drilling Units.* Curbs, gutters, and drains which collect contaminants associated with the drilling operation on a mobile drilling unit shall be installed as required by subparagraph 1.1.3.1. Curbs, gutters, and drains which collect contaminants not associated with the drilling operation are subject to regulation by the U.S. Coast Guard.

1.1.4 *Discharges from Fixed Platforms, Structures, Artificial Islands, and Mobile Drilling Units.* Discharges from fixed platforms or structures and mobile drilling units, including sanitary waste, produced water, drilling mud, and deck drainage, are subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended.

1.2 *Solid Material Disposal.*

1.2.1 *Well Solids.* The disposal of drill cuttings, sand, and other well solids containing oil is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Supervisor.

1.2.2 *Containers.* Containers and other similar solid waste materials shall not be disposed of into the ocean.

1.2.3 *Equipment.* Disposal of equipment into the ocean is prohibited except under emergency conditions. The location and description of equipment disposed of into OCS waters shall be reported to the U.S. Coast Guard in accordance with paragraph 4 of OCS Order No. 1.

2. *Personnel, Inspections, and Reports.*

2.1 *Personnel.* The lessee's personnel shall be instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Contractor personnel providing services offshore shall be informed in writing, prior to executing contracts, of the lessee's obligations to prevent pollution and of the provisions of this Order.

2.2 *Pollution Inspections.*

2.2.1 *Manned Facilities.* Manned drilling and production facilities shall be inspected daily to determine if pollution is occurring. Maintenance or repairs which are necessary to prevent pollution of the OCS waters shall be undertaken and performed immediately.

2.2.2 *Unattended Facilities.* Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected daily or at intervals prescribed by the District Supervisor to determine if pollution is occurring. Daily inspections may be postponed in the event of adverse weather conditions. Necessary maintenance or repairs shall be made immediately.

2.3 *Pollution Reports.* All spills of oil and liquid pollutants shall be reported orally to the District Supervisor and shall be confirmed in writing. All reports shall include the cause, location, volume of spill, and action taken. Reports of spills of more than 5.0 cubic meters (31.5 barrels) shall include information on the sea state, meteorological conditions, size, and appearance of slick. All spills of oil and liquid pollutants shall also be reported to the U.S. Coast Guard in accordance with the procedures contained in 33 CFR 135.305 and 135.307.

2.3.1 *Spills.* Spills shall be reported orally within the following time limits:

a. Within 12 hours, if spills are 1.0 cubic meters (6.3 barrels) or less.

b. Without delay, if spills are more than 1.0 cubic meters (6.3 barrels).

2.3.2 *Observed Malfunctions.* Lessees shall notify each other of observed pollution resulting from another's operation.

3. *Pollution-Control Equipment and Materials and Oil Spill Contingency Plans.* The lessee shall submit a description of procedures, personnel, and equipment that will be used in reporting, cleanup, and prevention of the spread of any pollution resulting from an oil spill which might occur during exploration or development activities. The following subparagraphs describe the minimum requirements for pollution-control equipment and procedures.

3.1 *Equipment and Materials.* Pollution-control equipment and materials shall be maintained by, or shall be available to, each lessee at an offshore location or at a location approved by the Deputy Conservation Manager (DCM), Offshore Field Operations. The equipment shall include containment booms, skimming apparatus, cleanup materials, chemical agents and other items needed for the existing climatic conditions, and shall be available prior to the commencement of drilling and production operations. The equipment and materials shall be inspected monthly and maintained in a state of readiness for use. The results of the inspections shall be recorded and maintained at the site.

3.2 *Oil Spill Contingency Plans.* The lessee shall submit an Oil Spill Contingency Plan for approval by the DCM, Offshore Field Operations, with or prior to submitting an Exploration Plan or a Development and Production Plan. Oil Spill Contingency Plans shall be reviewed annually. All modifications of the Oil Spill Contingency Plan and the results from the review of the plan shall be submitted to the DCM, Offshore Field Operations, for approval. The Oil Spill Contingency Plan shall contain the following:

a. Provisions to assure that full resource capability is known and can be committed during an oil spill, including the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally, both committed and uncommitted, and the time required for deployment of the equipment.

b. Provisions for varying degrees of response effort depending on the severity of the oil spill.

c. Provisions for identifying and protecting areas of special biological sensitivity.

d. Establishment of procedures for the purpose of early detection and timely notification of an oil spill including a current list of names, telephone numbers, and addresses of the responsible persons and alternates on call to receive notification of an oil spill, and the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil spill is discovered.

e. Provisions for well-defined and specific actions to be taken after discovery and notification of an oil spill, including:

(1) Specification of an oil spill response operating team consisting of trained, prepared, and available operating personnel.

(2) Predesignation of an oil spill response coordinator who is charged with the responsibility and is delegated commensurate authority for directing and coordinating response operations.

(3) A preplanned location for an oil spill response operations center and a reliable communications system for directing the coordinated overall response operations.

(4) Provisions for disposal of recovered spill materials.

4. *Drills and Training.*

4.1 *Drills.* Drills for familiarization with pollution-control equipment and operational procedures shall be the lessee's responsibility and shall be held at least once every 12 months by the lessee or a contractor serving the lessee. The personnel identified as the oil spill response operating team in the Contingency Plan shall participate in these drills. The drills shall be realistic and shall include deployment of equipment. A time schedule with a list of equipment to be deployed shall be submitted to the DCM, Offshore Field Operations, for approval. The drill schedule shall provide sufficient advance notice to allow U.S. Geological Survey personnel to witness any of the drills. Drills shall be recorded, and the records shall be made available to U.S. Geological Survey personnel. Where drill performance and results are deemed inadequate, the DCM, Offshore Field Operations, may require an increase in the frequency or a change in the location of the drills until satisfactory results are achieved.

4.2 *Training.* The lessee shall ensure that training classes for familiarization with pollution-control equipment and operational procedures are provided for the oil spill response operating team. The supervisory personnel responsible for directing the oil spill response operations shall receive oil spill control instruction suitable for all seasons. The lessee shall retain course completion certificates or attendance records issued by the organization where the instruction was provided. These records shall be available to any authorized representative of the U.S. Geological Survey upon request.

5. *Spill Control and Removal.* Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action taken under the lessee's Oil Spill Contingency Plan shall be subject to modification when directed by the DCM, Offshore Field Operations. The primary jurisdiction to require corrective action to abate the source of pollution shall remain with the DCM, Offshore Field Operations, pursuant to the provisions of this Order and the Memorandum of Understanding (MOU) between the Department of Transportation (U.S. Coast Guard) and the Department of the Interior (U.S. Geological Survey), dated August 16, 1971. The use of chemical agents or other additives shall be permitted only after approval by the DCM, Offshore Field Operations, in accordance with Annex X, National Oil and Hazardous Substances Pollution Contingency Plan, and in accordance with the previously mentioned MOU.

6. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic OSC Order No. 8—Effective February 27, 1981

Platforms and Structures

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10 and 30 CFR 250.11 and in accordance with 30 CFR 250.18.

1. *Applicability.*

1. *New Platforms.* Subsequent to the effective date of this Order, all new fixed or bottom-founded platforms or other structures (e.g., single-pile caissons, ice islands, and gravel islands) shall be designed, fabricated, and installed in accordance with the applicable provisions of the document, entitled "Requirements for Verifying the Structural Integrity of OCS Platforms," and shall require approval under the provisions of this Order.

Where doubt exists as to the applicability of this Order, questions shall be referred to the Deputy Conservation Manager (DCM), Offshore Field Operations.

1.2 *Major Modifications and Repairs.* Subsequent to the effective date of this Order, major modifications and repairs of damage to all fixed or bottom-founded platforms or other structures shall require approval by the DCM, Offshore Field Operations. Major modifications are defined as any structural change which materially alters the original plan or any major deviation from operations. Major repairs or damage are defined as operations involving members affecting the structural integrity of a portion of or all of the platform or other structure.

Repairs to primary structural elements may be made to restore an existing permitted condition without prior approval under emergency conditions. The DCM, Offshore Field Operations, shall be notified within 24 hours of the damage and subsequent repairs, and approval shall be obtained.

Where doubt exists as to the applicability of this Order, questions shall be referred to the DCM, Offshore Field Operations.

1.3 *Platform Verification.* All new platforms or other structures, and major modifications to platforms or other structures, shall be subject to review under the requirements of the Platform Verification Program and to the approval of the DCM, Offshore Field Operations.

1.4 *References.* Other aspects of the Platform Verification Program are described in more detail in the following documents, and these documents shall be considered as references for this Order.

1.4.1 *Operating Procedures for the OCS Platform Verification Program.* The document, entitled "Operating Procedures for the OCS Platform Verification Program," October 1979, describes the elements of the Platform Verification Program, the verification steps, the function of the Platform Verification Section, and the procedures for resolution of disputes, defines standards which shall be met by individuals or organizations in order to be approved as Certified Verification Agents (CVA); and provides instructions to the CVA.

1.4.2 *Requirements for Verifying the Structural Integrity of OCS Platforms.* The document, entitled "Requirements for Verifying the Structural Integrity of OCS Platforms," October 1979, is identified in this Order as "Requirements." It identifies mandatory state-of-the-art performance standards which shall be met in designing, fabricating, and installing platforms or other structures and major modifications to platforms or other structures.

1.4.3 *Appendices to Requirements for Verifying the Structural Integrity of OCS Platforms.* The document, entitled "Appendices to Requirements for Verifying the Structural Integrity of OCS Platforms," October 1979, is identified in this Order as "Appendices." It identifies alternative engineering design procedures which may be utilized, where applicable to conform to the "Requirements."

1.4.4 *Commentary on Requirements for Verifying the Structural Integrity of OCS Platforms.* The document, entitled "Commentary on Requirements for Verifying the Structural Integrity of OCS Platforms," October 1979, is identified in this Order as "Commentary." It provides an explanation of the basic intent of the "Requirements" and also discusses the "Requirements," the "Appendices," and the current relative development of the state of practice for pertinent parts of both.

2. *Responsibility.*

2.1 *Submission.* All applications for approval under the provisions of this Order shall be submitted to the DCM, Offshore Field Operations. All significant changes or modifications (i.e., any structural change which materially alters the original plan or any major deviation from operations) to approved applications shall be submitted for approval to the DCM, Offshore Field Operations. The lessee assumes risk of making changes or modifications without prior approval of the DCM, Offshore Field Operations. Where doubt exists as to whether a change is significant, questions shall be referred to the DCM, Offshore Field Operations.

2.2 *Certification.* The lessee shall have detailed structural plans and specifications for new platforms or other structures and major modifications certified by a registered professional structural engineer or civil engineer specializing in structural design. The lessee shall also sign and date the following certification:

(Lessee) ———— certifies that the design of the *(structure/modification)* has been certified by a registered professional structural engineer or a civil engineer specializing in structural design, and the *(structure/modification)* will be fabricated, installed, and maintained as described in the application and any approved modification thereto. Certified design and as-built plans and specifications will be on file at ————.

2.3 *Verification.* The lessee shall nominate a CVA(s) in the verification plan and have the design, fabrication, and installation of all platforms or other structures and modifications to platforms or other structures which are subject to review under the requirements of the Platform Verification Program, verified by a CVA(s).

2.4 *Approval.* For new platforms or other structures and major modifications thereto subject to review under the requirments of the Platform Verification Program, the lessee shall obtain approval for the design and fabrication from the DCM, Offshore Field Operations, prior to transporting the platform or other structure to the installation site.

2.5 *Notification.* The lessee shall be responsible for notifying the DCM, Offshore Field Operations, at least 1 week prior to transporting the platform or other structure to the installation site.

3. *Submissions.*

3.1 *General.* The lessee shall submit to the DCM, Offshore Field Operations, in triplicate, all documentation necessary for approval of new platforms or other structures and major modifications in accordance with the provisions of this Order. Listed hereafter is the documentation which shall be submitted, however, more detailed information and data may be required on a case-by-case basis and upon specific request by the DCM, Offshore Field Operations.

3.2 *Design.*

3.2.1 *Design Documentation.* The lessee shall submit design documentation with or subsequent to the submittal of the Exploration Plan or the Development and Production Plan. The design documentation shall include design drawings and material specifications for primary load-bearing members included in the space frame analysis, the certification by the lessee, and the name of the registered professional engineer. In addition, the design documentation shall incorporate the following:

a. General platform information.

b. Environmental and loading information.

c. Foundation information.

d. Structural information.

3.2.1.1 *General Platform Information.* The general platform information shall include the following:

a. Identification data including the platform or structure designation, the lease number, the area name, the block number, and the lessee's name.

b. Location data consisting of longitude and latitude coordinates, Universal Transverse Mercator grid system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection system, and a plat drawn to a scale of 1 centimeter = 240 meters (1 inch = 2,000 feet) showing surface location and distance from the nearest lease lines.

c. Intended primary use and other intended functions such as planned drilling, production, processing, well protection, compression, pumping or storage facility, or other operations.

d. Personnel facilities, personnel access to living quarters, number and location of boat landings, heliports, cranes, and evacuation routes.

e. Platform or structure details which consist of drawings, plats, front and side elevations of the entire structure, and plan views that clearly illustrate the following: essential parts (i.e., equipment arrangement, number and location of well slots); design loading of each deck; water depth; nominal size and thickness of all primary load-bearing jacket and deck structural members; nominal size, makeup, thickness, and design penetration of piling.

f. Corrosion protection or durability details which consist of the corrosion-protection method; expected life; and durability criteria for the submerged, splash, and atmospheric zones.

3.2.1.2 *Environmental and Loading Information.* The environmental and loading information shall include the following:

a. Environmental data, which consist of a summary listing of data, as addressed in the "Requirements," that have a bearing on the design, installation, and operation (e.g., wave heights and periods, current, vertical distribution of wind and gust velocities, water depth, storm and astronomical tide data, marine growth, snow and ice effects, and air and sea temperatures).

b. Derived loads which consist of a listing of total design functional loads and loads due to wind, wave, ice, and current forces for longitudinal, transversal, and diagonal approaches.

3.2.1.3 *Foundation Information.* The foundation information shall include the following:

a. Seabed testing results which consist of a brief summary of the major strata encountered at the location of the boring(s) presented in tabular form, a detailed subsurface profile illustrating results of field and laboratory testing, a listing of field and laboratory investigations and tests with a basis summary of resultant determinations, the identification of properties and conditions of the seabed and the subsoil, and the identification of any manmade hazards or obstructions.

b. Load effects which consist of a description of the effect of the environmental and functional loads on the foundation.

c. A soil stability report including a determination, with supporting information, of the susceptibility or non-susceptibility of the area to soil movement and, if susceptible to soil movement, an analysis of slope and soil stability.

d. Foundation design criteria which consist of a summary of the design criteria as specified in the "Requirements."

e. Seafloor survey results which consist of a summary of the survey specified in the "Requirements."

3.2.1.4 *Structural Information.* The structural information shall include the following:

a. Design life criteria which consist of the identification of the basis of the design life of the structure.

b. Design loading and criteria which consist of a summary description of the design load conditions and design load combinations taking into consideration the worst environmental and operational conditions anticipated over the service life of the platform or structure.

c. Material specifications which consist of a listing and description of the appropriate specifications.

d. Design strength criteria which consist of a description of the method(s) used in design (i.e., elastic, plastic ductility, ultimate).

e. Fatigue assessment details which consist of a summary of the fatigue analysis as specified in the "Requirements." The requirement for fatigue analysis shall be determined on a case-by-case basis. Where doubt exists concerning the requirement for this analysis, questions shall be referred to the DCM, Offshore Field Operations.

3.2.2 *Design Verification Plan.* For new platforms or other structures, and for modifications which are subject to review under the requirements of the Platform Verification Program, the lessee shall submit a design verification plan with or subsequent to the submittal of the Development and Production Plan. The verification plan shall include a short summary which nominates the CVA, states the qualifications of the CVA, describes how the lessee intends to use the CVA, identifies the level of work to be performed by the CVA, and identifies the documents which will be furnished with the platform application. Furthermore, the documentation listed under 3.2.1, as well as computer program descriptions which consist of abstracts of the computer programs used or to be used in various phases of the design process, shall be submitted as a part of the design verification plan.

The design verification plan shall be resubmitted for approval if the CVA changes, if the CVA's qualifications change, or if the level of work to be performed by the CVA changes. However, the summary of technical details need not be resubmitted unless changes are made in the technical details.

3.3 *Fabrication.* For new platforms or other structures and for modifications which are subject to review under the requirements of the Platform Verification Program, the lessee shall submit a fabrication verification plan subsequent to the submittal of the design. The plan shall include a short summary which nominates the CVA, states the qualifications of the CVA, describes how the lessee intends to use the CVA, identifies the level of work to be performed by the CVA, and identifies the documents which will be furnished to the CVA. The plan shall include fabrication drawings and material specifications of all the primary load-bearing members included in the space-frame analysis and a summary description of the following:

a. Structural tolerances.

b. Welding procedures.

c. Fabrication standards.

d. Material quality-control procedures.

e. Methods and extent of Nondestructive Examinations (NDE) for welds and materials.

f. Quality assurance procedures.

The fabrication verification plan shall be resubmitted for approval if the CVA changes, if the CVA's qualifications change, or if the level of work to be performed by the CVA changes. However, the summary of technical details need not be resubmitted unless changes are made in the technical details.

3.4 *Installation.* For new platforms or other structures and for modifications subject to review under the requirements of the Platform Verification Program, the lessee shall submit an installation verification plan subsequent to the submittal of the fabrication verification plan. The plan shall include a short summary which nominates the CVA, states the qualifications of the CVA, describes how the lessee intends to use the CVA, identifies the level of work to be performed by the CVA, and identifies the documents which will be furnished to the CVA. The plan shall also include a summary description of the planned marine operations, contingencies considered, alternate courses of action, and a summary description of the inspections to be performed during marine operations, including a graphical identification of areas to be inspected and acceptance/rejection criterion. The installation verification plan shall be resubmitted for approval if the CVA changes, if the CVA's qualifications change, or if the level of work to be

performed by the CVA changes. However, the summary of technical details need not be resubmitted unless changes are made in the technical details.

For structures fabricated and installed in place (e.g., ice islands and gravel islands), the fabrication and installation verification plans may be combined.

4. *Records.* The lessee shall compile, retain, and make available for review for the functional life of the platform or other structure that is subject to the provisions of this Order, the as-built structural drawings, the design assumptions and analysis, and a summary of the NDE records.

5. *Departures.* All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division, Alaska Region, Arctic OCS Order No. 12—Effective February 27, 1981

Public Inspection of Records

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.3, 250.34, 252.6, and 43 CFR Part 2. Requests for information made under the Freedom of Information Act, 5 U.S.C. 552, will be governed by the provisions of 43 CFR Part 2 (40 FR 7304, February 19, 1975).

1. *Filing of Reports.* All reports on Forms 9–152, 9–330, 9–331, 9–331 C, 9–1869, 9–1870, and the forms used to report the results of multipoint back-pressure tests shall be filed by the lessee in accordance with the following:

a. All reports submitted on these forms shall include a copy with the words "Public Information" shown on the lower right-hand corner. This copy of the form shall be made available for public inspection.

b. All items on the form not marked "Public Information" shall be completed in full, and such forms and all attachments thereto shall not be available for public inspection.

c. The copy marked "Public Information" shall be completed in full except that the items described in subparagraphs 2.1 through 2.4 below, and the attachments relating to such items, may be excluded.

2. *Availability of Records.* The following records pertaining to leases and wells in the Outer Continental Shelf (OCS) and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Regional Office:

2.1 *Form 9–152—Monthly Report of Operations.* All information contained on this form shall be available except proprietary information which may be included in the remarks column. The lessee shall delete such proprietary data from the public information copy.

2.2 *Form 9–330—Well-Completion or Recompletion Report and Log.*

2.2.1 *Prior to Commencement.* Prior to commencement of production, all information contained on this form shall be available except:

a. Item 1a, Type of Well.

b. Item 4, Location of Well, at top production interval and at total depth.

c. Item 22, If Multiple Completion, how many.

d. Item 24, Producing Interval.

e. Item 26, Type Electric and Other Logs Run.

f. Item 28, Casing Record.

g. Item 29, Liner Record.

h. Item 30, Tubing Record.

i. Item 31, Perforation Record.

j. Item 32, Acid, Shot, Fracture, Cement Squeeze, Etc.

k. Item 33, Production.

l. Item 37, Summary of Porous Zones.

m. Item 38, Geological Markers.

2.2.2 *After Commencement of Production.* After commencement of production, all information shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers.

2.2.3 *5 Years' Elapsed Time.* If production has not commences after an elapsed time of 5 years from the date of filing form 9–330 as required in 30 CFR 250.38(b), excluding the total time that operations and production are suspended by direction of the Secretary of the Interior, or his duly authorized representative, and further excluding the total time that operations and production are stopped or prohibited by Court Order, all information contained on this form shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, exclusive of exceptions noted above, the lessee shall file a Form 9–330 containing all information requested on the form except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9–330.

2.3 *Form 9–331—Sundry Notices and Reports on Wells.*

2.3.1 *"Request for Approval to."* When used as a "Request for Approval to" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, at top production interval and at total depth, and Item 17, Described Proposed or Completed Operations.

2.3.2 *"Subsequent Report of."* When used as a "Subsequent Report of" operations, and after commencement of production, all information contained in this form shall be available, except information contained in Item 17 pertaining to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

2.4 *Form 9–331 C—Application for Permit to Drill, Deepen, or Plug Back.* All information contained on this form and the location plat attached thereto shall be available except Item 4, Location of Well at Proposed Production Zone, and Item 23, Proposed Casing and Cementing Program.

2.5 *Form 9–1869—Quarterly Oil Well Test Report.* All information contained on this form shall be available.

2.6 *Form 9–1870—Semiannual Gas Well Test Report.* All information contained on this form shall be available.

2.7 *Multipoint Back Pressure Test Report.* All information contained on this form shall be available.

2.8 *Sales of Lease Production.* All information contained on the monthly U.S. Geological Survey computer printout showing sales volumes, value, and royalty on production of oil, condensate, gas, and liquid products by lease shall be available.

2.9 *Availability of Inspection Records.* All accident-investigation reports, pollution-incident reports, facilities-inspection data, and records of enforcement actions are also available for public inspection.

2.10 *Availability of Data and Information Submitted by Lessees.* Certain information submitted by lessees, as a result of OCS Orders and OCS Notices to Lessees and Operators, is nonproprietary in nature, or release of such information is necessary for the proper development of the lease. This information will be made available for public inspection, except for those portions which the lessee shall designate, with the approval of the Deputy Conservation Manager (DCM), Offshore Field Operations, as trade secrets and commercial for financial information which is privileged or

confidential. The available information will include:

a. Notices of support activity.

b. Oceanographic and meteorological data collected from drilling units and production facilities during the period of operations.

c. Results of site surveys required prior to drilling or placement of platforms or structures, such as shallow geologic hazards surveys, archaeological/cultural resource surveys, or other surveys related to the placement of platforms or structures.

d. Drawings, maximum environmental design criteria, and rated capability data of mobile drilling units and structures.

e. Oil Spill Contingency Plans.

f. Critical Operations and Curtailment Plans.

g. Other data required under 30 CFR 250.34.

2.11 *Expired Leases.* All information is available upon the expiration of a lease.

3. *Information Exempt from Public Inspection.* The information in subparagraphs 2.1 through 2.4 which has been restricted from public inspection is classified as geological and geophysical data. Except as provided in 30 CFR 250.3, 250.4, and 252.7, the release of this data is subject to the following restrictions:

3.1 *Leases Issued Prior to June 11, 1976.* For leases issued prior to June 11, 1976, the classified data is exempt from disclossure under exemption No. (9) of the Freedom of Information Act [5 U.S.C. § 552(b)(9) and 43 CFR 2.13 subsection (c), *Statutory Exemptions,* (9)].

3.2 *Leases Issued After June 11, 1976.* For leases issued after June 11, 1976, the classified data is available in accordance with 30 CFR 250.3, *Data and information to be made available to the public,* as follows:

a. Geophysical data, processed geophysical information, and interpreted geological and geophysical information shall not be available for public inspection, except as provided in 2.10c, without consent of the lessee as long as the lease remains in effect or for a period of 10 years after the date of submission, whichever is less, unless the DCM, Offshore Field Operations, with the approval of the Director, determines that earlier release of this infromation is necessary for proper development of the field or area.

b. Geological data and analyzed geological information shall not be made available for public inspection without the consent of the lessee as long as the lease remains in effect or for a period of 2 years after the date of submssion, whichever is less, unless the DCM, Offshore Field Operations, with the approval of the Director, determines that earlier release of such information is necessary for the proper development of the field or area. In accordance with 30 CFR 250.38, *Well Records,* data and well records shall be transmitted to the DCM, Offshore Field Operations, upon request or, if not requested, within 30 days following completion of suspension of any well. For the purpose of orderly release of data, in all cases the date of submission will be considered to be 30 days following such completion or suspension.

4. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

[FR Doc. 81-6539 Filed 2-26-81; 8:45 am]

BILLING CODE 4310-31-M